TIGHT GAS RESERVOIRS · PART I



UNCONVENTIONAL GAS SOURCES

NATIONAL PETROLEUM COUNCIL · DEC. 1980

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John F. Bookout, Chairman—Committee on Unconventional Gas Sources

NATIONAL PETROLEUM COUNCIL

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PREFACE

By letter dated June 20, 1978, the National Petroleum Council (NPC), an industry advisory committee to the Secretary of Energy, was requested to prepare an analysis of potential natural gas recovery from Devonian Shale, coal seams, geopressured brines, and tight gas reservoirs. In requesting the study, the Secretary stated that:

> ...Your analysis should assess the resource base and the state-of-the-art of recovery technology. Additionally, your appraisal should include the outlook for cost and recovery of unconventional gas and should consider how government policy can improve the outlook. (See Appendix A for complete text of the Secretary's letter and a further description of the National Petroleum Council.)

To aid it in responding to this request, the National Petroleum Council established a Committee on Unconventional Gas Sources under the chairmanship of John F. Bookout, President and Chief Executive Officer, Shell Oil Company. R. Dobie Langenkamp, Deputy Assistant Secretary for Resource Development & Operations, Resource Applications, U.S. Department of Energy, served as Government Cochairman of the Committee. A Coordinating Subcommittee and four task groups, by source, were formed to assist the Committee. The Tight Gas Reservoirs Task Group was chaired by C. Ovid Baker, Manager of E & P Research Planning, Mobil Research & Development Corporation, and cochaired by Lucio D'Andrea of the Department of Energy. (Rosters of the study groups responsible for this volume are included in Appendix B.)

The National Petroleum Council's report on Unconventional Gas Sources is being issued in five volumes:

- Volume I - Executive Summary
- Volume II - Coal Seams
- Volume III - Devonian Shale
- Volume IV - Geopressured Brines
- Volume V - Tight Gas Reservoirs (Parts I and II).

The Coal Seams, Devonian Shale, and Geopressured Brines volumes were issued in June 1980. The Executive Summary and Tight Gas Reservoirs volumes are being issued in December 1980. Part II of the Tight Gas Reservoirs volume presents detailed appraisals of 12 basins and supports the analyses presented in Part I of that volume.

For each source, reserve additions and producing rates are calculated at five gas prices, three rates of return, and at least two levels of technology. Constant January 1, 1979, dollars were used in all analyses. The report presents estimates of what could happen under certain assumed technical and economic circumstances and is not intended to represent a forecast of what will occur.

Inflation adjustment for 1979 prices: The economic results presented in this report are expressed in constant January 1979 dollars. These can be easily converted to constant dollars in a different base year if the weighted average inflation rate for investment and operating expense from 1979 to the new year is known or can be estimated. Usually, drilling and/or fracturing costs dominate; therefore, inflation rates in these cost categories will generally be applicable.

CONCLUSIONS

Based on detailed appraisals of a large number of known tight gas formations and the expertise of the study participants, it is the judgment of the study participants that natural gas recovery from low permeability (tight) reservoirs could make a very significant contribution to future U.S. energy supply. The findings set forth in this report form the basis for the following specific conclusions:

- The amount of tight gas expected to be recoverable is very large. Within the price and technology parameters used in this study, potential ultimate recovery is projected to be in the range of 192-574 trillion cubic feet (TCF) for the total United States (excluding Alaska). This is equivalent to approximately 33-98 billion barrels of crude oil. It is possible that recovery might significantly exceed this range due to possible conservatism in the extrapolation from the detailed appraisal areas to the total United States, about which less was known. Approximately half the potential ultimate recovery can be added to reserves by the year 2000.

- The potential production of natural gas from tight reservoirs is estimated to be sufficient to increase U.S. gas production substantially above present levels. It is possible that by the year 2000 as much as 4-16 TCF of tight gas could be produced annually. These levels of production could account for 4-14 percent of total U.S. energy requirements in the year 2000. Potentially insecure and expensive oil imports could be reduced significantly by the year 2000 with a concerted development program of lower cost tight gas.

- Exploration and development of tight gas resources involve risk and uncertainty. The usual surface exploration methods are of little value in locating a well because the gas does not exist in conventional, structural traps and there is little physical difference between "dry" and "productive" areas. Once a productive formation has been drilled, its production rate must be increased by stimulation (usually massive hydraulic fracturing [MHF]). Risk and uncertainty can be reduced by improving reservoir characterization techniques and by increasing the reliability and efficiency of massive hydraulic fracturing. Such improvements in fracturing techniques are required for the adequate development of lenticular formations which contain more than 40 percent of the recoverable tight gas resource. Also, a productive area may be abandoned if the gas sales price is too low to provide an adequate return on investment. The percentage of prospects that are profitable increases significantly at the higher gas prices examined, reducing the risk of a productive area being abandoned.

- Much tight gas will be discovered and can begin to be produced above current levels at the Federal Energy Regulatory Commission (FERC) incentive ceiling price. As of September 22, 1980, this price was $4.59 per thousand cubic feet (MCF) ($3.33/MCF in January 1, 1979, dollars). Furthermore, as phased deregulation of gas prices now in progress is completed in the 1985-1987 period, competitive market forces and the need for security of energy supply are expected to encourage increased development of tight gas resources.

- Development of the U.S. tight gas resource will be as dependent on advances in technology and changes in well spacing rules as on price. Tight gas is technically recoverable using massive hydraulic fractures to create a deeply penetrating, conductive drainage path into the formation. With current (base) technology, fracture lengths (from well bore to tip) do not generally exceed 1,000 feet. With advanced technology it may be possible to create fractures of 4,000-foot lengths. Future advanced technology will provide approximately 50 percent more recoverable gas than current base technology. It will possibly take six to 10 years of intensive research and approximately four to eight years of development to fully achieve advanced technology for widespread routine application.

- Tight gas is widespread in favorable formations, but it is most economically attractive in areas of thicker, more permeable rocks (sweet spots). The field boundaries are set not only by structural traps but also by permeability, thickness, and economics. The primary objective of exploration technology is to find the sweet spots. Geology and petrophysics will play a greater role than seismic exploration in the development of tight gas.

- There is a major opportunity to recomplete old wells, otherwise ready for abandonment, into profitable producers of gas from tight formations. Rates of return have been estimated to be more favorable for recompletions than for tight gas new field wildcats. Investments are less and risk is much lower.

- Initially, new tight gas production is expected to come from basins in the Southwest region. This region is now producing declining amounts of conventional gas and has excess pipeline capacity. Significant tight gas production can begin in western regions within a decade contingent upon the construction of a major pipeline system.

- Development of the U.S. tight gas resource should have a minimal impact on the environment compared to the development of other energy forms. Also, federal lands withdrawn from development or under consideration for withdrawal, while potentially affecting other resources, comprise a very small portion of the tight gas areas considered potentially productive.

SUMMARY

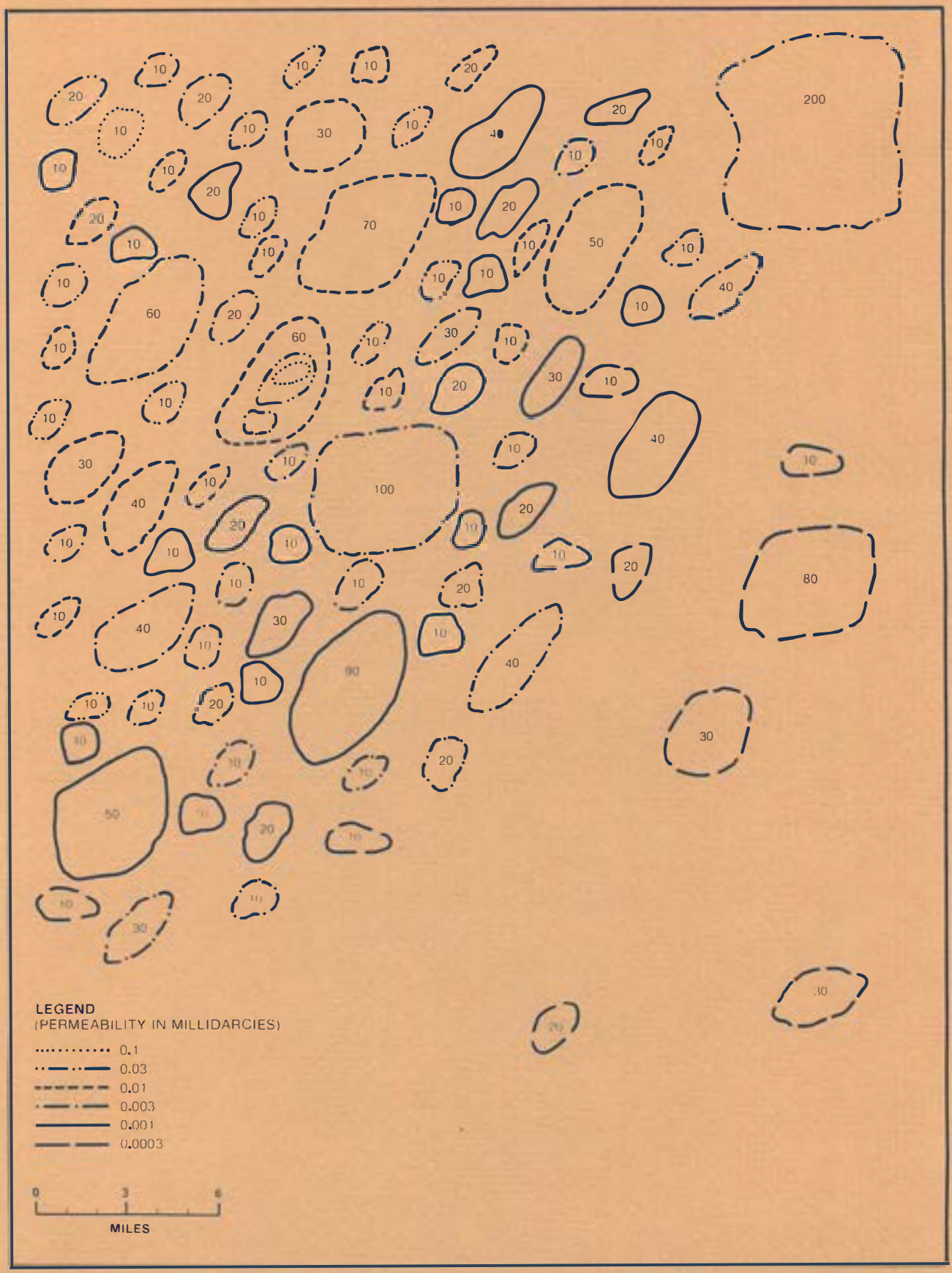
BACKGROUND

For the purposes of this study, tight gas is defined as natural gas in either blanket (continuous) or lenticular formations that have an in situ effective permeability of less than 1 millidarcy (md). Historically, most of these formations have been uneconomical to produce due to the low natural flow rates of the gas. Tight gas is widespread in favorable formations. However, economic tight gas is found only in the better quality reservoir rock. The field boundaries are set not only by structural and stratigraphic traps but by permeability and economics.

A typical distribution of tight gas fields in a 1,000 square mile portion of an example formation is shown in Figure 1. In this illustration, 88 tight gas fields are drawn to scale as they might occur in the formation. The gas fields have average permeabilities ranging from 0.1 to 0.0003 md. The permeability may be a tenfold range in the vertical direction and perhaps a three or fourfold range in a horizontal direction across a given field. The effective average permeability is the one used in well production calculations in this report. The fields with lower permeability values require higher gas prices if they are to be economic to produce. The higher permeability fields that can be produced at lower prices are often called "sweet spots." Outside of the boundaries of these gas fields, the formation permeability is assumed to be 0.00001 md or less.

An understanding of lenticular gas resources is very important as they contain more than 40 percent of the recoverable tight gas expected to be found. A lenticular formation contains many lenses within the fields. These are represented to scale in Figure 2. Although some of the actual lenses are curved, they have been represented as rectangular. The lenses occur in stacks of perhaps 50 to 200 lenses in depth. The numbers in the corners of Figure 2 indicate the number of lenses of that size that would occur per 100 lenses. This illustration covers an area of one square mile, indicating the magnitude of these lenses. Four wells are shown in this section, with 1,000-foot fractures. Since these fractures are several hundred feet in height, it is possible to contact many lenses.

Recently the outlook for significantly increased production of tight gas has been enhanced by increases in gas price and the introduction of massive hydraulic fracturing techniques which create a large area in the low permeability formations from which gas can flow into a single well. A fractured well, by exposing considerably more of a formation's rock face, can produce many times the amount of gas that an unfractured well can. Figure 3 shows the manner in which fractures penetrate blanket and lenticular formations. A fractured well in a tight gas formation typically produces at a lower rate but over a longer period than a well in a conventional formation. (See the Production Technology section of



NOTE: Numbers used within gas field boundaries refer to recoverable gas per field (BCF); area outside field boundaries has permeability of 0.00001 millidarcies or less.

Figure 1. Example of Tight Gas Field Distribution.

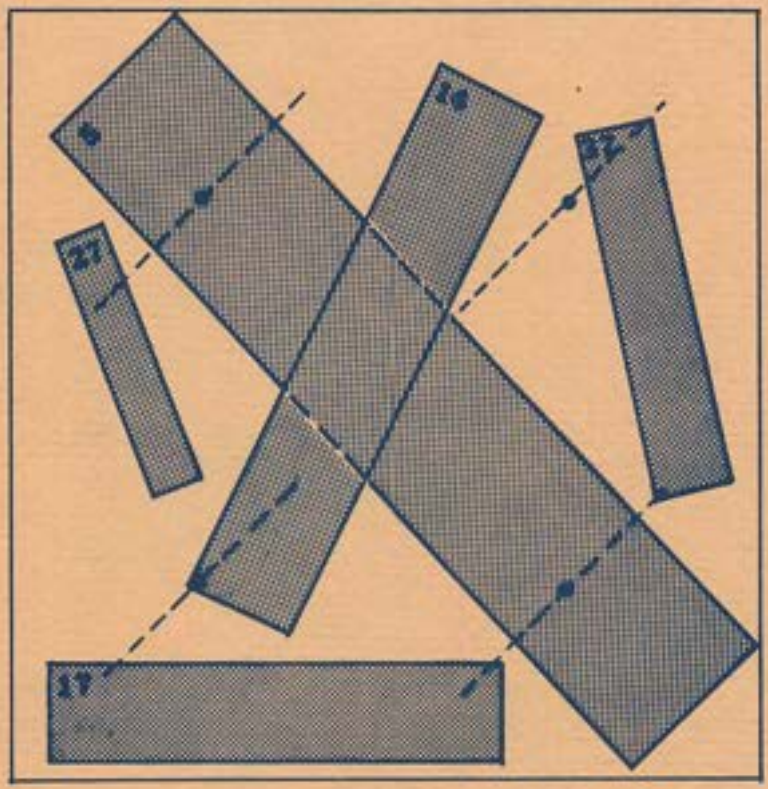


Figure 2. Lenticular Formation—Typical Areal Lenses in One Section (Square Mile).

Chapter Seven for a detailed discussion of tight gas reservoir characteristics and recovery methods.)

It has been estimated that by 1978 as much as 0.8 TCF per year was being produced from tight gas formations.[1] This report analyzes only the incremental tight gas potential and does not include that from areas previously developed and currently being produced.

METHODOLOGY

There are 113 basins and provinces that presently produce gas in the United States (excluding Alaska). This study has concentrated on 12 of these basins that have been identified as containing tight gas formations and for which extensive data are available. A detailed appraisal was made of the tight gas resource in these basins. This detailed appraisal accounted for approximately 35 percent of the total U.S. area (in the lower 48 states) thought to contain tight gas. The estimates from these detailed appraisals were then extrapolated to the remaining 65 percent to arrive at a total estimate of the tight gas resource in the lower 48 states.

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[1] DOE's Energy Information Administration 1979 Annual Report to Congress.

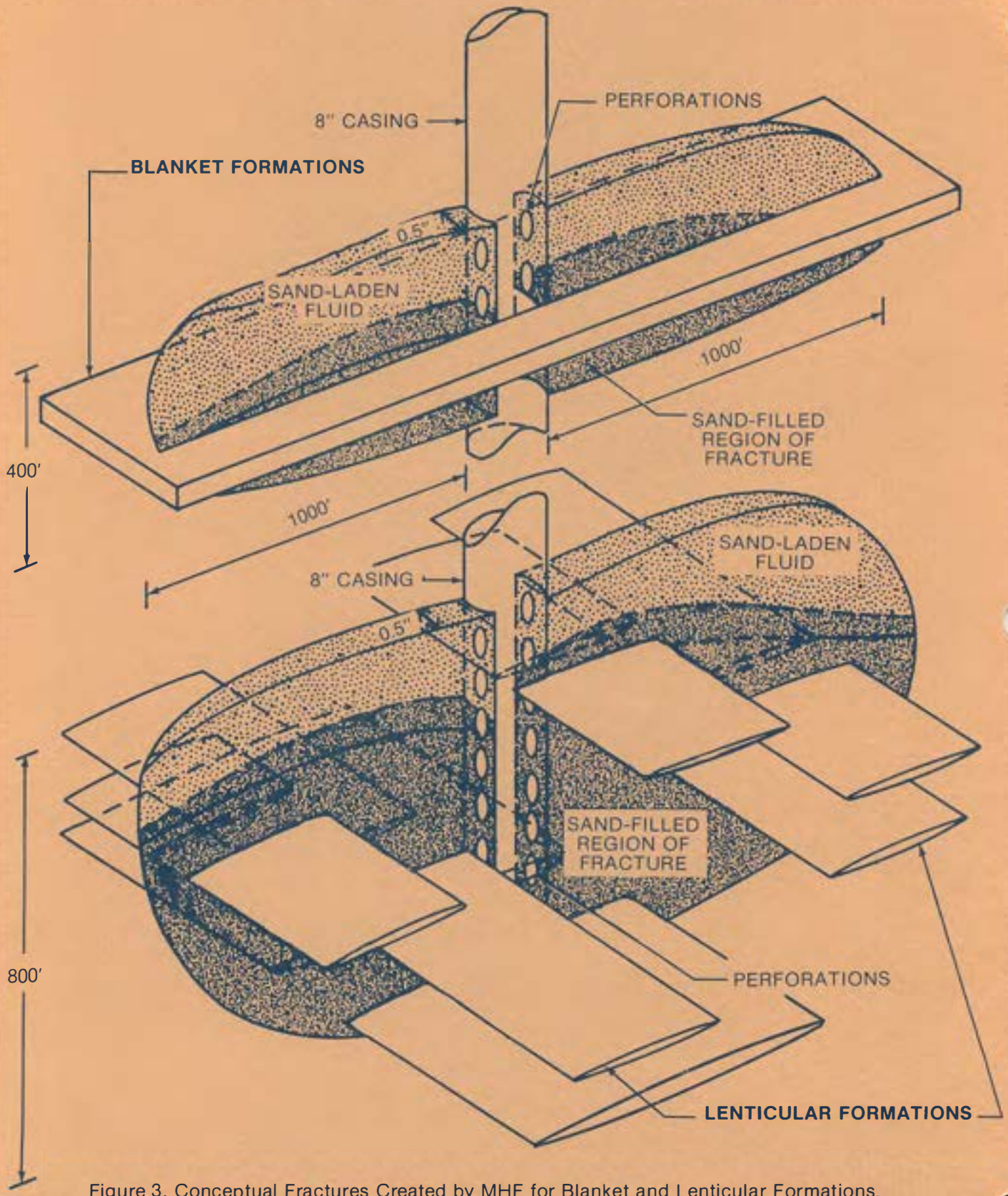


Figure 3. Conceptual Fractures Created by MHF for Blanket and Lenticular Formations.

The evaluation of U.S. tight gas potential included estimating the following values:

- Total prospective area for tight gas in sections (i.e., square miles)
- Potentially productive tight gas area in sections (i.e., square miles)
- Total gas in place
- Maximum recoverable gas in place
- Ultimate recoverable gas as a function of gas price and technology
- Estimated producing rates which might be expected from tight gas reservoirs as a function of gas price and technology.

Potential ultimate recovery is calculated as a function of eight gas prices ($1.50, $2.50, $3.10, $3.50, $5.00, $7.00, $9.00, and $12.00 per thousand cubic feet [MCF]), three discounted marginal real rates of return (10, 15, and 20 percent), and two levels of technology. These marginal rates of return are the minimum rates of return to the producer for the highest cost (last) increment of recovery at a given price.

Tight gas was assumed to have an average heating value of 1,000 Btu per cubic foot; thus, a price of $5.00/MCF equates to $5.00 per million Btu (MMBtu) which is equivalent to crude oil at $29.00 per barrel. Also, constant January 1, 1979, dollars are used in all analyses.

The marginal rates of return are used as a minimum, solely to determine if a given prospect is to be considered profitable for inclusion as an economically recoverable resource, and do not represent expected average rates of return for the industry. The rates of return calculated in the basin chapters of Part II of the Tight Gas Reservoirs volume are expected real industry average rates of return on investment, after tax, and take risk into account. They do not reflect inflation. Returns for individual companies will vary widely around these averages.

Two levels of technology are used for evaluation. Current fracturing technology and well spacing regulations represent a base case in this report. Fracture lengths of 1,000 feet from well to tip and spacings of 160 acres per well are now in use. An advanced technology and modified field regulation case that could be developed over the next decade is also evaluated. It assumes fracture lengths up to 4,000 feet and well spacing as low as 53 acres.

To move to advanced technology will require a significant research effort. New and improved methods are needed to measure and estimate in situ permeability, net pay values, and the distribution and character of lenticular reservoirs. Methods must be developed

to determine the vertical distribution of local stresses in a well bore, the areal distribution of regional stresses, and the azimuth of hydraulically induced fractures. Techniques are required to predict and control fracture geometry (length, height, etc.) and to improve fracture conductivity. In addition, new fracturing materials (fluids and proppants) must be developed, as well as methods for predicting their behavior. It will probably require a research expenditure on the order of $1.5 billion over a period of 15 years to achieve fully advanced technology.

Possible producing rates for the total tight gas resource were calculated under several scenarios, incorporating various development schedules and economic assumptions. The marginal 15 percent rate of return was used in more scenarios for several reasons. The amount of resource and the production rate at a given price were found to be rather insensitive to the marginal rate of return. The expected average discounted cash flow rate of return was thought to be the real criterion for operators selecting areas for tight gas plays.

During the period of this study, the acceleration of inflation changed the participants' outlook. In this environment, it was expected that most operators would not accept the technical risks involved in tight gas exploration below a real marginal rate of return of 15 percent. Unfamiliar technology commonly requires a higher risk premium, especially in the years it is being introduced to the industry.

FINDINGS

Tight Gas Resource and Recovery

The U.S. tight gas resource and the amount expected to be recoverable for both the appraised and extrapolated areas are summarized in Table 1. The appraisal of the 12 selected basins represents a much higher level of confidence than the values determined for the extrapolated areas.

The results of this study strongly indicate that tight gas potential reserve increases are about equally dependent on price increases and a successful research and development program. For example, Table 1 indicates that potential recovery would be 192 TCF for the base case at $2.50/MCF, and 503 TCF for the advanced case at $5.00/MCF. Of this 311 TCF potential increase, 139 TCF would result by moving from the base to the advanced case at $2.50/MCF, and 172 TCF would result by increasing the price from $2.50 to $5.00/MCF in the advanced case.

Results -- Twelve Appraised Basins

The 113 gas-producing basins and provinces in the United States (both onshore and offshore) cover approximately 3.5 million sections (square miles). Of this total area, it is estimated that there are approximately one million sections which may be considered prospective tight gas areas. The appraised study of the 12

TABLE 1

U.S. Tight Gas Resource and Recovery Estimates
Appraised and Extrapolated Areas
(Lower 48 States)

	Appraised (12 Basins)	Extrapolated (101 Basins)	Total*
Prospective Area (Sections)	359,500	655,000	1,014,500
Productive Area (Sections)	53,000	68,500	121,500
Total Gas in Place (TCF)	444	480	924
Maximum Recoverable (TCF)	293	315	608
Base Technology -- Recoverable (TCF)†			
@ $2.50/MCF	97	95	192
$5.00	165	200	365
$9.00	189	215	404
Advanced Technology -- Recoverable (TCF)†			
@ $2.50/MCF	142	189	331
$5.00	231	272	503
$9.00	271	303	574

*Totals may not add due to rounding.
†At a 15 percent discounted rate of return and constant January 1, 1979, dollars.

selected basins covers about 359,500 sections. Approximately 53,000 of these 359,500 sections are considered to be potentially productive areas. In the 12 appraised basins, 444 TCF is estimated as gas in place, of which approximately 231 TCF is potentially recoverable at $5.00/MCF, a 15 percent discounted rate of return, and advanced technology.

Results -- Extrapolation to the Total United States

Of the one million sections in the United States which may be considered prospective tight gas areas, approximately 120,000 sections are considered to be potentially productive areas with about 924 TCF estimated gas in place. The maximum recoverable gas (i.e., physical upper limit regardless of price or technology) is estimated at about 608 TCF. For the total United States, estimated ultimate recoverable tight gas as a function of price and technology is in the range of 192-574 TCF. At a price of $5.00/MCF, a 15 percent discounted rate of return, and advanced technology, the estimated recoverable gas for the United States is on the order of 503 TCF.

Significance of Tight Gas Resource

The U.S. tight gas resource, economically recoverable at $5.00/MCF (January 1, 1979, dollars), a 15 percent discounted rate of return, and advanced technology and field rules, is compared to recent estimates of proven reserves and undiscovered potential for conventional gas in Table 2. Potential tight gas recovery is 503 TCF compared to a potential of approximately 1,000 TCF for conventional gas.

TABLE 2

Economically Recoverable U.S. Gas Resources -- Lower 48 States
(TCF)

	Appraised Areas (12 Basins)			Extrapolated Areas (101 Basins)		Total (113 Basins)
	Southwest	Rocky Mountains	Northern Great Plains	Greater Southwest	Other Lower 48 States	
Proven Reserves (12-31-79)*						
Conventional	9	4	1	119	18	151
Tight†	7	3	1	1	--	12
Undiscovered Gas Potential						
Land Conventional§	54	140	20	268	133	615
Offshore Conventional§	--	--	--	114	105	219
Total Conventional	54	140	20	382	238	834
Tight (NPC)¶	22	113	95	100	172	503
Total Gas	92	260	117	602	428	1,500
Percentage Tight Gas	24	44	81	17	40	33

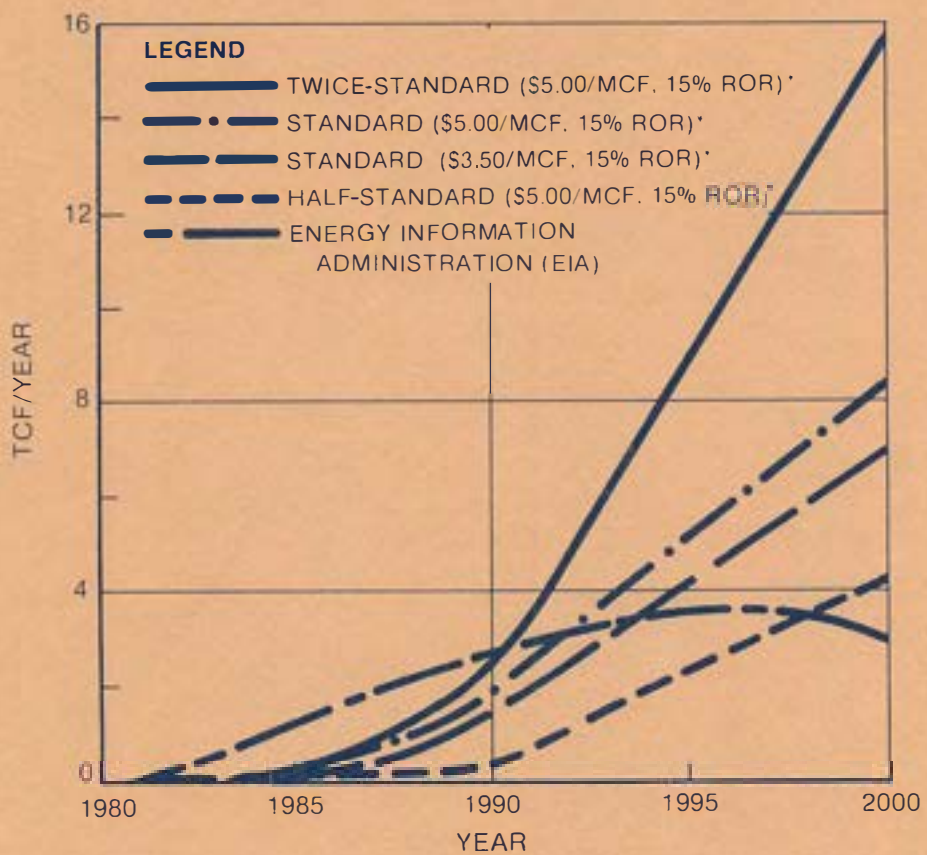
*American Gas Association (Tables 51 and 53).
†Estimated tight gas portion of January 1, 1979, AGA estimates of proven reserves.
§Potential Gas Committee.
¶At $5.00/MCF (January 1, 1979, dollars), a 15 percent rate of return, and advanced technology and field rules.

Tight Gas Producing Rates

Potential producing rates for the large tight gas resource are dependent upon the development schedule employed. For the purposes of this study, a standard scenario was developed to assess producing rates. This scenario assumes a specific development schedule and a phasing-in of advanced case technology. The sensitivity of producing rates to economic variables was tested by computing the scenario at various prices and rates of return. As a further test, producing rates were calculated for scenarios about twice and half the standard scenario. Also, a scenario was developed to assess the potential in the Southwest region for tight reservoir recompletions in existing wells.

Producing Rate Results

Figure 4 shows possible total U.S. producing rates in the 1980-2000 period for the standard, twice-standard, and half-standard scenarios at $5.00/MCF and a 15 percent discounted rate of return as well as for the standard scenario at $3.50/MCF and a 15 percent discounted rate of return. The Energy Information Administration (EIA) projection for tight gas in Figure 4 agrees closely with a half-standard scenario that includes large amounts of gas from



*Constant January 1, 1979, dollars.

Figure 4. Tight Gas Production Rates—Comparison of Scenarios.

recompletion of old wells in the Southwest region (see Table 70). Figure 5 shows possible producing rates to the year 2070 for the standard scenario at $5.00/MCF and a 15 percent discounted rate of return.

With a $3.50/MCF gas price and the standard scenario, annual tight gas production could reach about 7 TCF by the year 2000. However, with $5.00/MCF and the standard scenario, it is possible that by the year 2000 as much as 8 TCF of this tight gas could be produced annually. This level of production could account for 8 percent of total U.S. energy requirements in the year 2000. Furthermore, the cumulative amount of tight gas recovered by the year 2000 would only be about 12 percent of the recoverable U.S. resource. Tight gas could be produced at the annual rate of 8 TCF or more until 2030 and at a declining rate until 2070, as shown in Figure 5.

Significance of Tight Gas Producing Rates

Projected gas supplies for the United States for the 1980-2020 period were published by the U.S. Department of Energy's Energy Information Administration (EIA) in its 1979 Annual Report to Congress. A summary of this projection is shown in Table 3. EIA's

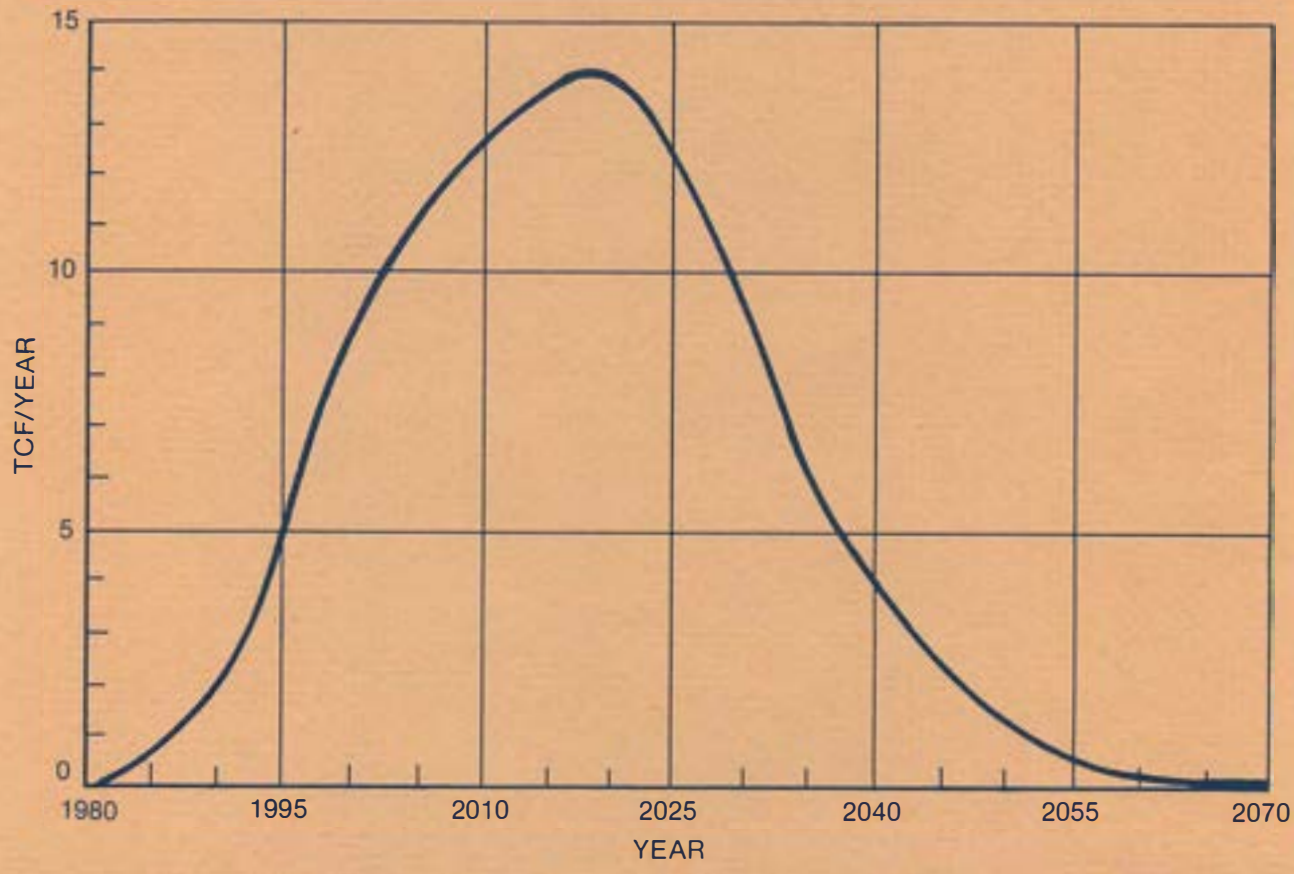


Figure 5. Lifetime Production Rates for 500 TCF of Tight Gas—Standard Scenario, Annual Production 1981-2070.

TABLE 3

Energy Information Administration (EIA) 1979 Forecast of U.S. Gas Supplies*
(TCF)

EIA	1978	1985	1990	1995	2000	2010	2020
Conventional Lower 48	18.4	16.1	14.6	12.4	11.3	9.5	7.3
Alaska	0.2	0.2	1.1	1.4	1.6	1.9	1.8
Unconventional	0.9	1.9	3.0	4.0	3.4	3.2	3.1
Tight Gas	0.8	1.8	2.8	3.8	3.2	3.0	2.9
Devonian Shale Gas	0.1	0.1	0.2	0.2	0.2	0.2	0.2
Synthetics	0.0	0.1	0.1	0.1	0.1	0.5	1.3
Imports	0.9	0.8	0.8	0.8	0.7	0.2	0.1
Total Gas Supply	20.4	19.1	19.6	18.7	17.2	15.3	13.5
Percentage U.S. Supply from Tight Gas	4%	9%	14%	20%	19%	20%	23%
NPC							
Unconventional Developed Before 1980†	0.9	0.5	0.3	--	--	--	--
Unconventional (@ $5.00/MCF) Developed After 1980§	0.0	0.6	3.1	8.6	11.5	13.5	14.9
Tight Gas	0.0	0.2	1.8	5.2	8.3	11.3	14.0
Devonian Shale Gas	0.0	0.3	0.7	0.8	0.9	0.7	0.3
Coal Seam Gas	0.0	0.1	0.6	2.6	2.3	1.5	0.6
Geopressured Gas	0.0	0.004	0.006	0.008	0.008	0.0	0.0
Total Gas Supply¶	20.4	18.3	20.0	23.3	25.3	25.6	25.3
Percentage U.S. Supply from New Tight Gas	0%	1%	9%	22%	33%	44%	55%

*EIA 1979 Annual Report to Congress, with lower portion of table revised to substitute NPC estimate for unconventional gas.

†Includes declining production from 1978 unconventional gas reserves not otherwise shown in NPC study.

§Price in constant January 1, 1979, dollars.

¶EIA forecast with substitution of NPC unconventional gas projections.

projections indicate a more rapid decline in gas production than shown by the results of this study, which indicate significantly more gas production from unconventional gas sources and particularly from tight gas; this projection is shown at the bottom of Table 3. Potential U.S. gas supplies for the 1980-2020 period resulting from the addition of NPC unconventional gas projections to the EIA forecast of other gas sources is shown in Figure 6.

A projection of U.S. energy supplies from all sources and world oil prices for the 1980-2020 period, based on EIA's 1979 Report to Congress, is shown in Table 4. Gas prices in January 1, 1979, dollars on an energy equivalent to oil price basis are also shown in Table 4. This equivalent gas price should reach $5.00/MCF early in 1981.

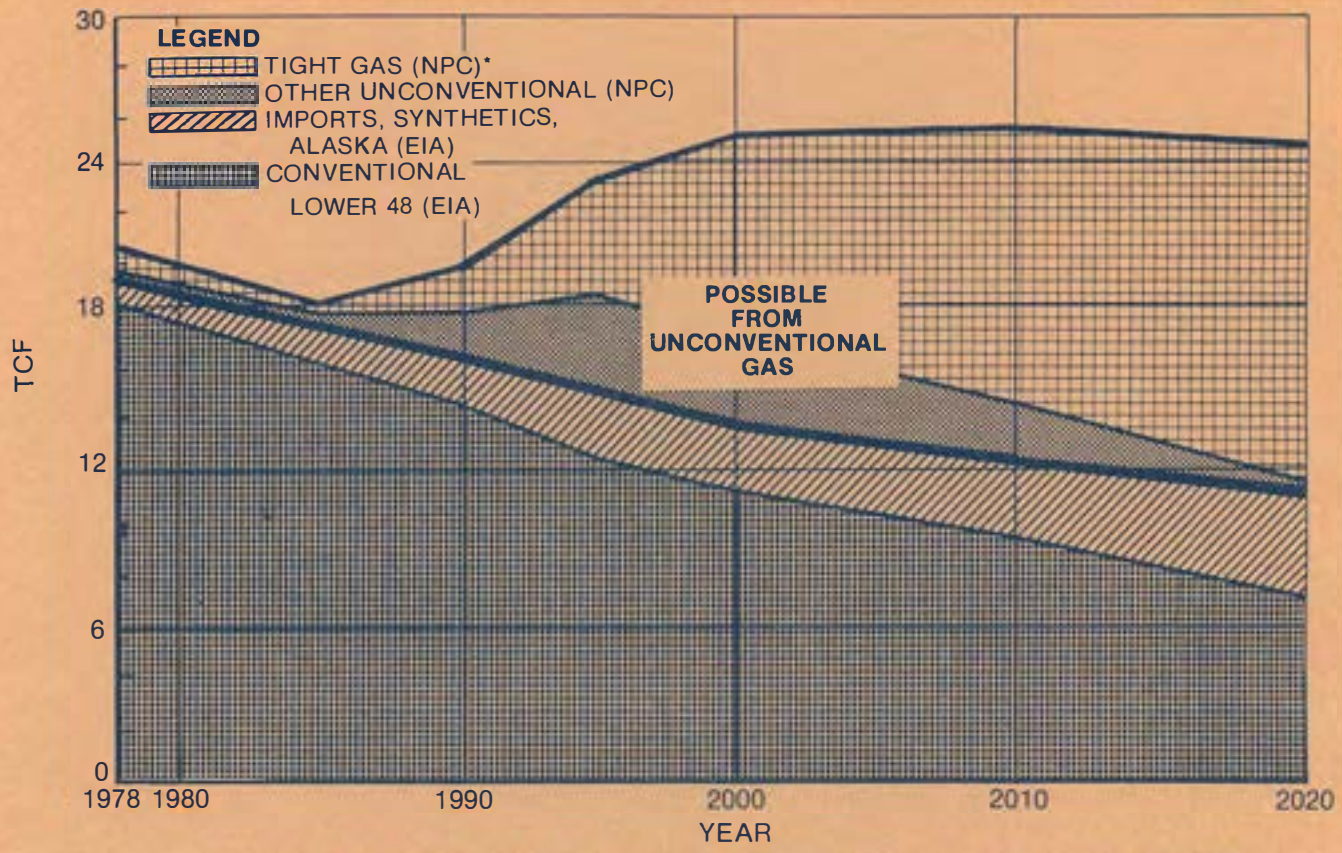


Figure 6. 1979 Energy Information Administration (EIA) Forecast of Gas Supplies with NPC Unconventional Gas Projections.

*Assumes $5.00/MCF (January 1, 1979, dollars), a 15 percent discounted rate of return, and phase-in of advanced technology.

The price of tight gas is currently regulated at a ceiling price of $4.59/MCF (as of September 22, 1980), twice the regulated price of new domestic conventional onshore gas. For reference in this report, the current price equates to $3.33/MCF in January 1, 1979, dollars. At current prices, much tight gas can begin to be produced above present levels. Moreover, as phased deregulation of gas prices now in progress is completed in the 1985-1987 period, competitive market forces and the need for security of energy supply are expected to encourage increased development of tight gas resources.

For example, assuming a $5.00/MCF gas price and the standard scenario (Figure 4), tight gas production could reduce projected oil imports shown in Table 4 by over 60 percent by the year 2000. For such to occur, industry and government must embark on a concerted tight gas development program involving a major research and development effort to improve applied technology, a change in field rules to allow closer well spacing, and an increase in real prices for tight gas.

Exploration Success and Risk

While government can create a favorable environment, the ultimate scale of tight gas development will be contingent upon a belief by the nation's gas explorers, producers, and transporters

TABLE 4

Energy Information Administration (EIA) 1979 Forecast of U.S. Energy Supply*
(Quadrillion Btu/Yr or TCF/Yr Equivalents)

	1978	1980	1985	1990	1995	2000	2010	2020
Domestic Oil	20.7	20.5	18.7	19.6	19.4	20.5	20.6	15.0
Oil Imports	16.7	15.0	12.1	11.7	11.8	13.1	8.4	6.8
Domestic Gas	19.5	19.0	18.2	18.7	17.8	16.4	14.6	12.1
Gas Imports	0.9	1.6	0.8	0.8	0.8	0.7	0.2	0.1
Coal	15.0	17.6	25.0	29.3	36.7	38.2	49.7	71.6
Nuclear	3.0	2.9	5.6	8.2	9.6	11.3	18.1	21.8
Renewable, Solar, and Other	2.6	1.4	1.2	0.8	0.4	7.9	12.4	16.0
Total	78.4	78.0	81.6	89.1	96.5	108.1	124.0	143.4
World Oil Price								
Mid-1979 $/Bbl	15.50	31.00	32.00	37.00	41.00	43.00	43.00	43.00
January 1, 1979, $/MCF Equivalent Gas Price	2.52	4.92	5.08	6.02	6.51	6.83	6.83	6.83

*U.S. Energy Information Administration (EIA) 1979 Annual Report to Congress, Table S-2, p. X.

that a large tight gas resource exists and is economically producible. Geologists and investors can find details about basins and formation characteristics for the 12 basins in the chapters of Part II of this volume. The basic data on net pay, porosity, production rates, probability of success, investment requirements, and average rates of return for 82 subbasins are discussed in the text and are tabulated. The economic data may be used to make a rough ranking of the subbasins and to select favorable areas for potential tight gas plays. Geologists explore formations having favorable geochemical and thermal history for gas generation. Many of these are known from dry holes drilled into the formations in the past. Many prospective areas can be located by reexamining old well records for gas shows.

Seismic work can contribute little to wildcat locations. Pattern drilling must be used to locate good quality reservoir rock. Long fractures help to enlarge the area tested by a single well. As reservoir quality measured in millidarcy-feet decreases, the risk of drilling an uneconomical well becomes greater. When the gas price goes up, these lower quality reservoirs become profitable. The probable range of reservoir quality can be estimated before drilling but the actual quality at the specific well location is unknown. Geologists search for better quality reservoir rocks by drilling along natural fracture concentrations, following lenticular reservoirs, and working along trends of previous discoveries. Since the drilling objective is for a higher value of millidarcy-feet, it would seem prudent to prefer the thicker formations. The best guide, of course, is previous exploration and development experience. The basin chapters of Part II of this volume reflect that experience in terms of economics and risk.

The risk involved is reflected in the value of the percentage of prospects profitable given for each subbasin. These values represent the estimated average performance of the whole industry. Individual operators could expect to approach these average performances if engaged in large plays involving many prospects. Smaller operators may spread their risks by owning a small share of many prospects. Among people who drill only one or two wells, very few can expect financial success until prices are much higher than they are now.

Potential Constraints

The following potential constraints to the development of tight gas were considered in this study:

- Market demand at the prices necessary to produce the gas may not be available until the late 1980's.
- More operators will have to become convinced that the production technology is dependable, the gas resources are available, and the economics are favorable before many tight gas plays are begun.
- Pipeline capacity is a constraint now in many parts of the country, but new pipelines can be built as needed.

- The supply of materials, manpower, and services is not likely to be a constraint, except for the highest production rates.
- The investment requirements will not be a constraint.
- Federal lands proposed for withdrawal, and those already withdrawn from energy and other uses, could reduce the potential gas resources available by less than 5 percent in the lower 48 states. But access to federal lands is important to producing this resource.
- Environmental quality will be improved by increased gas production as opposed to supplies from most other energy sources.
- The new gas price regulations encourage tight gas development, and when gas prices are deregulated in 1985-1987, the pace of exploration should increase.

At the projected tight gas production levels developed for the standard scenario, the only potential constraint appears to be limited pipeline capacity in the Rocky Mountain and Northern Great Plains/Williston areas.

DISCUSSION

The findings of this extensive study of tight gas potential raise three pertinent issues, which are addressed below:

Why the Potential Recovery and Production Estimates Are So Large

The productive area increases rapidly with increased gas prices. For example, in the San Juan basin, the area that is productive increases from 75 sections (square miles) at a $2.50/MCF price to 1,040 sections at $9.00/MCF. The amount of recoverable gas resource increases 12 times for the same price change. This situation is typical of most basins. Wildcat wells that were formerly classified as dry holes can become successful producers at higher prices with a resultant improvement in wildcat success rates. Estimated recoveries are also significantly increased by improvements in applied technology and closer well spacing.

What the Regional Impact of Tight Gas Production Will Be

The Rocky Mountains and Northern Great Plains will be major gas producing provinces for nearly a century. Eight or more large gas transmission lines will be required to deliver the gas to markets east and west.

The excess pipeline capacity in the Southwest region will make possible prompt investigation of tight gas resources "behind the pipe" (gas resources from existing wells recompleted in tight formations), in old fields, and in new discoveries. About one fourth of the total U.S. tight gas potential is located in this region.

It is expected to sustain a buildup of production rates to a peak of 4 TCF per year in the year 2000 and decline to 2 TCF per year by 2020. Thus, the petroleum industry will have additional productivity in this region for many years.

Most states have the potential to produce tight gas. The development of this potential should lessen the possibility of local gas supply interruptions. Also, the search for the gas will increase the prospect of finding new oil reserves in most states.

How Tight Gas Production Can Get Started on a Large Scale

The Federal Energy Regulatory Commission (FERC) set an incentive price for tight gas of $4.59/MCF starting September 22, 1980. This is double the regulated price of new onshore gas. Existing oil or gas wells recompleted in tight gas formations can qualify for this incentive price. Many operators can begin a tight gas play in wells that have exhausted their conventional reserves. Only a workover and fracturing investment is required. There are thousands of such wells in the Southwest region of the United States.

New shallow wells in the Northern Great Plains can also be drilled and completed for modest investments. The FERC incentive price program could encourage tight gas drilling to the extent that the 1,000 wells presently producing tight gas could increase to 13,000 wells in 1985. It is expected that such a play would continue after deregulation in 1985 because the economics of recovery would already have been demonstrated in many basins.

The undiscovered U.S. tight gas potential is estimated to be in the range of 192-574 TCF. With price incentives and improved technology, tight gas reservoirs will be discovered and produced all across the United States.

Chapter One

INTRODUCTION

U.S. natural gas falls into three categories: (1) cumulative gas produced to date; (2) proven gas reserves that have actually been discovered; and (3) undiscovered resources that remain to be found and developed.

This study of gas in low permeability formations (tight gas) is a study of undiscovered gas resources in the (lower 48) United States. The broad message of this study is that there is a substantial tight gas resource potential to be developed. If gas prices were equivalent to world oil prices, significant quantities of tight gas could be produced at a profit. If technology can be advanced to achieve longer fractures it would be possible to produce about half again as much gas as can be recovered with current technology. Advanced technology can also reduce development costs.

For example, the Milk River gas field, now the largest in Canada with approximately 9 TCF of recoverable gas, was actually discovered by a Canadian Pacific Railroad well drilled for water in 1883, but was not economically producible until 1973.[1] One of the large gas fields in North America, the San Juan basin with 28 TCF of recoverable gas, is a very low quality reservoir which has also experienced a radical improvement in economics in response to improvements in gas price and technology.

OBJECTIVES

The objectives of this analysis of tight gas reservoirs and potential tight gas production in the United States are:

- To determine the producible reserves of tight gas that could be added from basins containing tight gas sands at prices of $2.50, $3.50, $5.00, $7.00, and $9.00/MCF. Make these determinations at discounted cash flow rates of return (DCF ROR) of 10, 15, and 20 percent. Economics are based on January 1, 1979, dollars.

- To make the estimates at the best level of current technology (base case) and also at an advanced technology (advanced case) that could be developed in five to 10 years with funding of research and testing.

- To estimate the amount of proven reserves that could be added up to the year 2000 at these prices and levels of technology.

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[1]John A. Masters, "Deep Basin Gas Trap, Western Canada," AAPG Bulletin, Vol. 63, Number 2, February 1979, pp. 152-181.

- To estimate the annual production rate of tight gas in the United States from 1980 to the year 2000.

- To show which government policies aid and which constrain the industry in reaching these potential production goals.

- To recommend research programs which should be pursued to reach the potential goals of the advanced technology case.

The total U.S. tight gas resource has been studied and the methodology used in this analysis is described in Chapters Three and Four.

BACKGROUND

The United States has 113 basins and provinces that currently produce gas. These 113 basins have been considered on a regional basis as follows and are shown on Figure 7:

- I -- Western region

- II -- Greater Southwest region

- III -- Eastern region

- IV -- Mid-Continent region

Twenty-four of these areas have been recognized as tight gas trends or basins and are listed on the following compilation. The location of these 24 basins is shown on Figure 7. Of the 24 recognized tight gas basins that have been studied, 12 have been analyzed extensively and are numbered in the following list. These 12 basins are considered to be significant sources of tight gas, and they have provided the most extensive data currently available. This study has concentrated on these 12 basins in this evaluation of U.S. tight gas potential.

For the purposes of the study, tight gas has been defined as natural gas that has an in situ effective permeability of less than 1 md. Most gas in this study is in reservoirs that have permeabilities of less than 0.1 md. Tight gas reservoirs require artificial stimulation and close spacing, resulting in higher costs. Because of the marginal nature of the reservoirs, the economic risks are high. Basins and rocks of specified geologic ages that meet these criteria include:

Area	Geologic Age
I. Western Region	
Great Plains Appraised	
1. Northern Great Plains	Cretaceous and older
2. Williston	Cretaceous and older

Rocky Mountain Appraised

3.	Greater Green River	Tertiary and older
4.	Wind River	Tertiary and older
5.	Uinta	Tertiary and older
6.	Piceance	Tertiary and older
7.	Denver	Cretaceous

Other Known Western

A.	Snake River	Tertiary
B.	Big Horn	Tertiary and older
C.	Wasatch	Tertiary and older
D.	Douglas Creek	Cretaceous
E.	Western Shallow Cretaceous Trend	Cretaceous

II. Greater Southwest Region

Southwest Appraised

8.	San Juan	Cretaceous
9.	Val Verde-Ozona Trend	Permo/Pennsylvanian
10.	Val Verde-Sonora Trend	Permo/Pennsylvanian
11.	Edwards Lime Trend	Cretaceous
12.	Cotton Valley Trend	Jurassic

Other Known Southwest

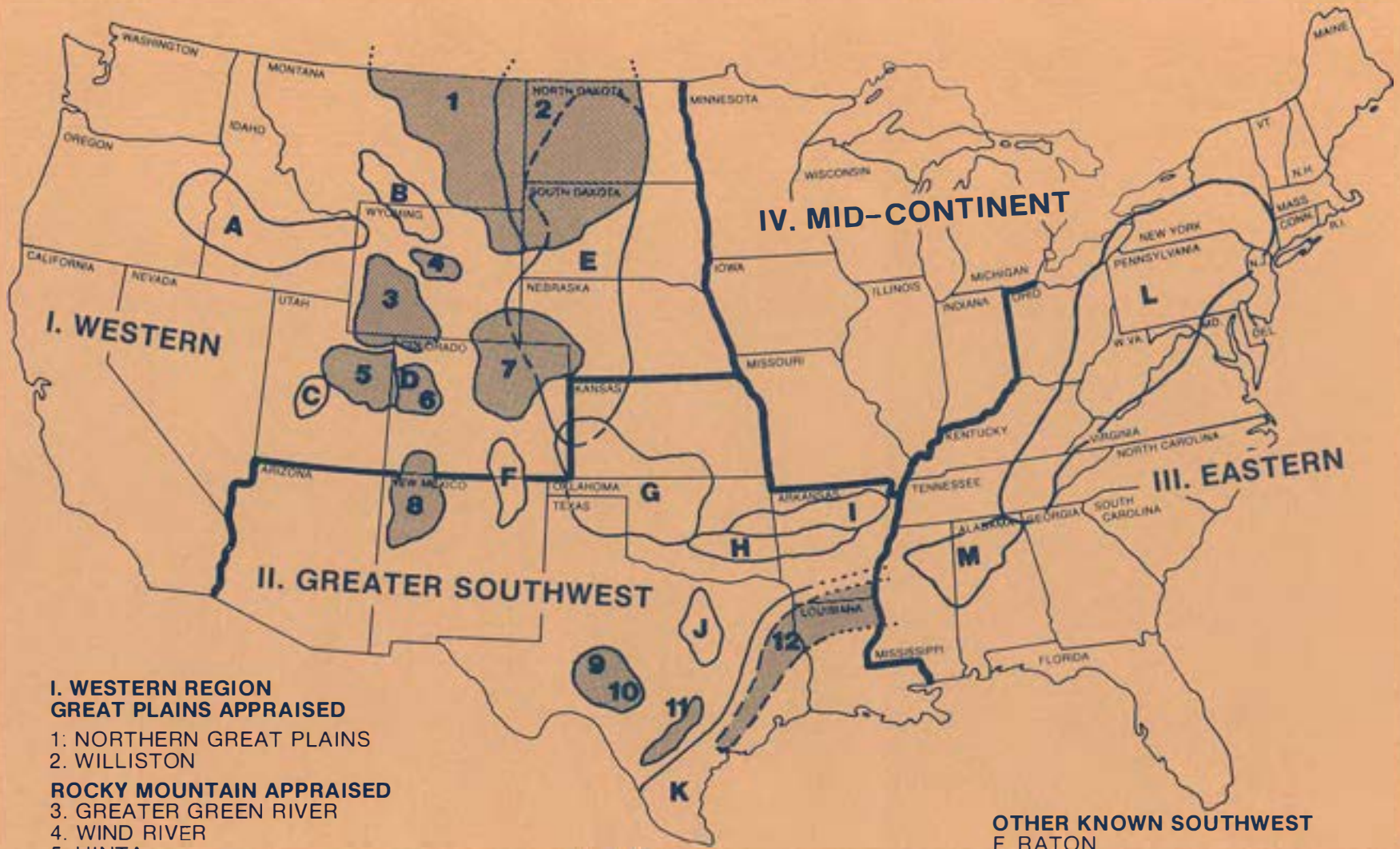
F.	Raton	Tertiary and older
G.	Anadarko	Paleozoic
H.	Ouachita	Paleozoic
I.	Arkoma	Paleozoic
J.	Fort Worth	Pennsylvanian
K.	Western Gulf	Tertiary

III. Eastern Region

L.	Appalachian	Paleozoic
M.	Black Warrior	Paleozoic

Geologic ages are specified because not all tight gas formations have been identified as yet by deep drilling, and it is anticipated that others will be identified as the tight gas resource is developed.[2]

[2]Many of these tight gas basins have been previously identified in Western Gas Sands, U.S. Energy Research and Development Administration, Project Plan, August 1, 1977.



I. WESTERN REGION
GREAT PLAINS APPRAISED

1: NORTHERN GREAT PLAINS
2. WILLISTON

ROCKY MOUNTAIN APPRAISED

3. GREATER GREEN RIVER
4. WIND RIVER
5. UINTA
6. PICEANCE
7. DENVER

OTHER KNOWN WESTERN

A. SNAKE RIVER
B. BIG HORN
C. WASATACH
D. DOUGLAS CREEK
E. WESTERN SHALLOW CRETACEOUS TREND

BASINS STUDIED BY NPC

II. GREATER SOUTHWEST REGION
SOUTHWEST APPRAISED

8. SAN JUAN
9. VAL VERDE-OZONA TREND
10. VAL VERDE-SONORA TREND
11. EDWARDS LIME TREND
12. COTTON VALLEY TREND

OTHER KNOWN SOUTHWEST

F. RATON
G. ANADARKO
H. OUACHITA
I. ARKOMA
J. FORT WORTH
K. WESTERN GULF COAST

III. EASTERN REGION

L. APPALACHIAN
M. BLACK WARRIOR

NOTE: Coastal regions include offshore areas.

Figure 7. Tight Gas Basins.

STUDY ORGANIZATION

This analysis of the 12 major U.S. tight gas basins identified to date was accomplished by means of an organization of 12 basin teams consisting of one or more geologists and engineers with experience in finding and producing tight gas in each of the respective basins. Individual basin chapters were developed by these teams, which also provided the judgments for the production and economics used in the study.

A group of engineers participating in the study effort made the engineering assumptions, set standards, gathered cost data, and selected calculation methods. Figure 8 presents an organization chart for this study and Figure 9 presents an indication of the work flow, which was ultimately accomplished as described in Chapters Three and Four.

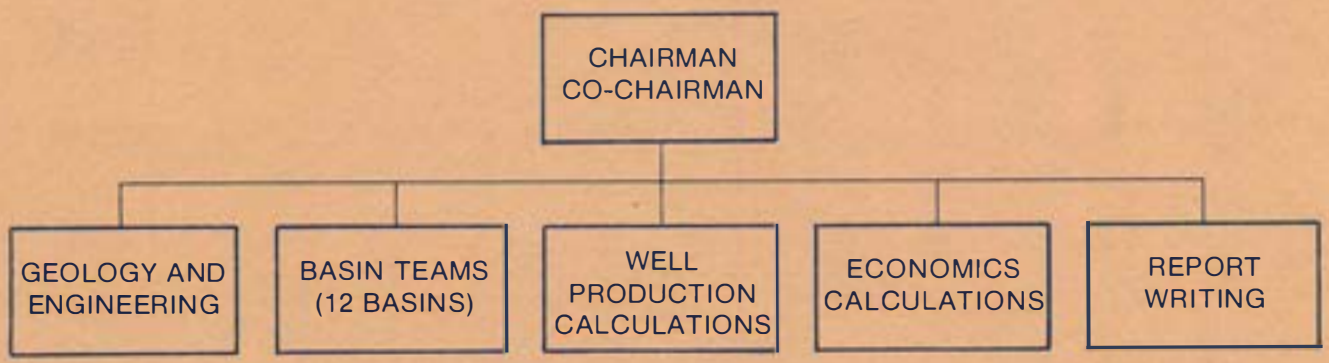


Figure 8. Organization Chart.

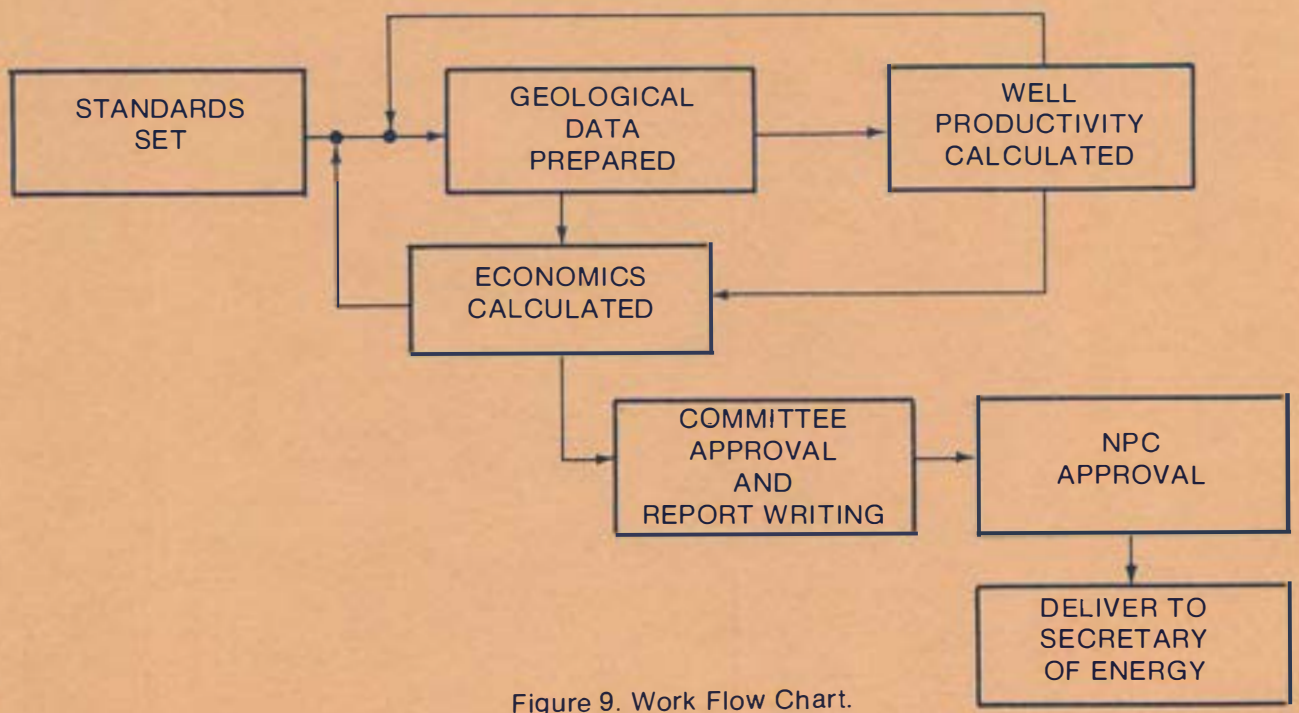


Figure 9. Work Flow Chart.

Chapter Two

THE SIZE OF THE TIGHT GAS RESOURCE

During the 1950's some tight gas wells were drilled and completed in the San Juan basin. However, it was not until the 1970's that activity commenced in the more favorable areas of other tight gas basins, such as the Cotton Valley, Denver, Green River, and Sonora. Tight gas production is currently economically possible by means of massive hydraulic fracturing. Experience with more than 1,000 wells has demonstrated the potential for production of low permeability gas reservoirs throughout the United States.

THE GENERAL APPRAISAL AND ESTIMATION APPROACH

The size of the U.S. tight gas resource appears to be quite large, yet its actual magnitude has not been well established. There are 113 known gas-producing basins and provinces (both conventional and tight) in the lower continental United States. It is estimated that there are approximately one million sections that can be considered prospective tight gas areas. To provide some measure of the tight gas resources 12 basins were selected which were considered representative of the potentially productive tight gas areas of the United States. These basins are shown in Figure 7. A detailed appraisal was made of the gas resource in these basins, which accounted for approximately 35 percent of the total U.S. area thought to contain tight gas. The estimates from the detailed appraisals were then extrapolated to the remaining prospective tight gas areas to arrive at a total estimate of the tight gas resource in the lower 48 states of the United States.

The appraisals of the 12 selected basins represent a much higher level of confidence than the values determined for the extrapolated areas. In the appraised areas, values were determined by means of the detailed formation-by-formation investigations as described in Chapters Three, Four, and Five. In the remaining extrapolated areas, projections were made using "typical" formation types which corresponded to the formations encountered in the 12-basin detailed appraisal study.

As stated above, the 12 appraised basins are depicted in Figure 7 and are listed in detail in Chapter One. The extrapolated areas include the other known tight gas basins (also listed in Chapter One and shown in Figure 7) plus all other speculative areas and additional speculative formations contained in the appraised basins but not included in the detailed appraisal study.

The study included determining the following values:

- Total prospective area for tight gas (sections; i.e., square miles)

- Potentially productive tight gas area (sections; i.e., square miles)
- Total gas in place
- Maximum recoverable gas in place
- Ultimate recoverable gas as a function of gas price and technology
- Estimated producing rates which might be expected from tight gas reservoirs.

The particular method used in this study to determine a measure of the resource (both in place and recoverable) has never before been applied on such a large scale. It may be possible that the method itself introduces more precision than the accuracy of the geological and reservoir data can justify. However, the method does employ a wide number of expert estimates from many qualified sources on specific data pertinent to the overall appraisal. These data were then brought together with procedures commonly used to evaluate exploration and development activity on a smaller scale. The same method used here could possibly be applied to each of the other 101 gas-producing basins and provinces in the United States to confirm estimates of the total gas potential (which were not appraised in detail in this study) from tight gas formations.

The basins studied in detail in this report can be classified as the Rocky Mountain basins, the Northern Great Plains/Williston group, and the Southwest, with basins in New Mexico, Texas, and northern Louisiana. At a selling price of $5.00/MCF, advanced technology, and a DCF ROR of 15 percent, the tight gas resource in these basins is estimated below:

Region	TCF
Southwest	22.4
Rocky Mountain	113.3
Northern Great Plains/Williston	95.3
Total	231.0

While a large area has been studied, an even larger, potentially productive area has been omitted. Kansas, Oklahoma, Arkansas, California, and most of Louisiana are not represented. Also, many states are known to have gas resources which have not been attractive at low prices. It seems reasonable to assume that this potential should be included in the report. In order to assign values

to these resources, conventional gas and oil production was considered to be indicative of sedimentary basins with tight gas potential. These categories are as shown below:

Region	TCF
Greater Southwest	100.0
Eastern	127.2
Mid-Continent	5.0
Western	40.0
Total	272.2

The speculative gas resource was thus raised from 231 to 503 TCF. The offshore areas probably contain tight gas. The extreme difficulties associated with the MHF technique, and the high costs of drilling and pipelining offshore, make such areas unattractive for tight gas production.

Because other areas in the United States were to be included in the scenarios in the study, basin analyses were needed for extrapolation. This need was met by assigning to these areas "typical" or surrogate basins already evaluated. For example:

Region		Represented by
Mid-Continent	Shallow:	Northern Great Plains: Mowry and Greenhorn, Niobrara, Carlile and Eagle, and Carlile and Niobrara
	Intermediate:	Val Verde: Sonora
	Deep:	San Juan: Dakota
Western	Shallow:	Wind River: Frontier, Muddy
	Intermediate:	Piceance: Corcoran Cozette, Fort Union, Mesaverde 8,000, and Lower Cretaceous Jurassic
Western	Deep:	Wind River: Lance 9,000 and 14,000
Eastern	Central:	Northern Great Plains: Mowry and Greenhorn, Niobrara, Carlile and Eagle, Carlile and Niobrara

Region		Represented by
	Coastal:	Piceance: Corcoran Cozette, Fort Union, Mesaverde 8,000, Lower Cretaceous Jurassic
	Intermediate:	San Juan: Dakota
	Deep:	Cotton Valley
Greater Southwest		Southwest: Cotton Valley, Edwards Lime Central, Edwards Lime Southwest, Val Verde: Ozona and Sonora, and San Juan: Dakota

COMPOSITE TIGHT GAS IN THE UNITED STATES

The results of the study for both the appraised and extrapolated areas are summarized in Table 5.

TABLE 5

U.S. Tight Gas Resource and Recovery Estimates
Appraised and Extrapolated Areas
(Lower 48 States)

	Appraised (12 Basins)	Extrapolated (101 Basins)	Total*
Prospective Area (Sections)	359,500	655,000	1,014,500
Productive Area (Sections)	53,000	68,500	121,500
Total Gas in Place (TCF)	444	480	924
Maximum Recoverable (TCF)	293	315	608
Base Technology -- Recoverable (TCF)†			
@ $2.50/MCF	97	95	192
$5.00	165	200	365
$9.00	189	215	404
Advanced Technology -- Recoverable (TCF)†			
@ $2.50/MCF	142	189	331
$5.00	231	272	503
$9.00	271	303	574

*Totals may not add due to rounding.
†At a 15 percent discounted rate of return and constant January 1, 1979, dollars.

The appraised study of the 12 select basins covers about 360,000 prospective sections. Of these, approximately 53,000 sections are considered to be potentially productive areas. In the 12 appraised basins, 444 TCF was estimated as gas in place, with 231 TCF being potentially recoverable at $5.00/MCF and a 15 percent discount rate of return, using advanced technology.

It appears that the United States has a substantial gas resource from tight formations at world energy prices. Although only 35 percent of the potentially productive area was appraised in detail, this represents approximately 48 percent of the maximum recoverable gas.

The data in Table 6 summarize the composite total U.S. estimates for the regions corresponding with the map in Figure 7. As can be seen, of the approximately one million prospective sections, an area of 121,500 sections contains 924 TCF of gas in place. The maximum recoverable gas (i.e., physical upper limit regardless of price or technology) is estimated at 608 TCF.

TABLE 6

Regional Summary of Tight Gas In Place

Region	Prospective Area (Sections)	Productive Area (Sections)	Estimated GIP (TCF)	Maximum Rec. Gas (TCF)
Western	311,200	58,900	469.9	315.0
Greater Southwest	403,300	20,600	227.5	139.9
Eastern	280,000	40,000	219.3	147.5
Mid-Continent	20,000	2,000	8.1	5.4
Total	1,014,500	121,500	924.8	607.8

Estimated ultimate recoverable gas as a function of price and technology is summarized in Table 7. This reflects the possible amount of gas estimated to be economically recoverable. It appears to be approximately 192-574 TCF, depending on price and technology. At a price of $5.00/MCF and advanced technology, the estimated recoverable gas for the United States is on the order of 503 TCF.

The estimates indicate that a large portion of the recoverable tight gas resource potential lies in the Western region. Most of the remaining tight gas is approximately evenly distributed in the Greater Southwest and Eastern regions, with about 1 percent remaining in the Mid-Continent region.

TABLE 7

Regional Summary of Recoverable Tight Gas
(15 Percent DCF ROR)
(TCF)

Region	Base			Advanced		
	$2.50	$5.00	$9.00	$2.50	$5.00	$9.00
Western	104.9	178.9	203.4	140.0	248.6	289.9
Greater Southwest	45.2	84.8	91.5	107.2	122.4	137.4
Eastern	40.7	97.7	104.9	80.0	127.2	141.9
Mid-Continent	1.3	3.7	3.9	4.0	5.0	5.3
Total	192.1	365.1	403.7	331.2	503.2	574.5

Basin Summary of Tight Gas

A breakdown by basin, which shows both the appraised and the extrapolated estimates, is given in Table 8. This information, plus that above for the total United States, is depicted in the form of a graph in Figures 10 through 16.

Approximately 80 percent of the area of the appraised basins, which covers some 360,000 prospective sections, lies in the Western region, with 53 percent in the Northern Great Plains/Williston basins and the remaining 27 percent in the Rocky Mountain area. The rest of the appraised area falls in the Greater Southwest region.

The extrapolated area contains approximately 655,000 prospective tight gas sections. The majority of the prospective extrapolated area is in the Greater Southwest (50 percent) and Eastern regions (43 percent). The remaining 7 percent is distributed approximately equally in the Western and Mid-Continent regions.

Formation and Subbasin Summary of Tight Gas

A detailed summary of the subbasin and formation distribution of the tight gas resource is given in Table 9. This lists the calculations determined for individual formations or groups of formations which were studied and appraised in significant detail. The various separate formations included in the detailed appraised study on each basin or subbasin are listed in Table 10. It should be noted that the study includes many areas where several separate formations, each of which is potentially productive, will overlie one another. In these cases the combined production from a stack

TABLE 8

Basin Summary of Tight Gas Resource

	Prospective Area (Sections)	Productive Area (Sections)	Estimated GIP (BCF)	Maximum Rec. Gas (BCF)	BCF Recoverable at Technology and Price (15% DCF ROR)					
					Base			Advanced		
					$2.50	$5.00	$9.00	$2.50	$5.00	$9.00
WESTERN REGION										
Great Plains (Appraised Areas)										
Northern Great Plains/Williston	188,900	32,730	147,747	100,186	54,731	77,727	80,322	73,989	95,358	99,341
Rocky Mountains (Appraised Areas)										
Greater Green River	28,300	8,938	136,068	86,517	3,076	30,754	46,156	12,351	52,000	74,377
Wind River	7,400	2,280	33,699	23,286	7,039	9,851	11,727	8,772	14,412	18,778
Uinta	9,500	1,184	20,465	15,269	12,220	13,236	13,380	14,759	15,269	15,269
Piceance	7,100	3,144	49,143	32,979	12,873	18,423	19,422	12,829	26,427	29,711
Denver	45,000	1,600	13,284	7,918	0	0	1,166	0	5,212	7,596
Total	97,300	17,146	252,659	165,969	35,208	72,264	91,851	48,711	113,320	145,731
Other Western (Extrapolated Areas)										
Shallow	7,300	2,300	8,024	6,100	3,529	4,381	4,586	5,430	6,100	6,100
Intermediate	15,700	6,000	53,254	37,108	11,463	22,217	23,732	11,883	30,500	33,976
Deep	2,000	700	8,243	5,647	0	2,401	2,928	0	3,400	4,847
Total	25,000	9,000	69,521	48,855	14,992	28,999	31,246	17,313	40,000	44,923
Total Region	311,200	58,876	469,927	315,010	104,931	178,990	203,419	140,013	248,678	289,995

TABLE 8 (Continued)

	Prospective Area (Sections)	Productive Area (Sections)	Estimated GIP (BCF)	Maximum Rec. Gas (BCF)	BCF Recoverable at Technology and Price (15% DCF ROR) Base $2.50	Base $5.00	Base $9.00	Advanced $2.50	Advanced $5.00	Advanced $9.00
GREATER SOUTHWEST REGION										
Southwest (Appraised Areas)										
San Juan	12,500	1,188	3,298	2,213	0	1,494	1,812	1,494	2,020	2,213
Val Verde - Ozona Trend	15,300	150	1,024	638	0	106	182	370	532	604
Val Verde - Sonora Trend	7,700	350	3,507	2,160	0	633	688	1,267	1,613	1,879
Edwards Lime Trend	858	450	14,254	8,648	2,142	6,211	6,734	8,062	8,451	8,648
Cotton Valley Trend	36,900	1,027	21,867	12,816	5,387	6,976	7,292	8,352	9,795	12,735
Total	73,258	3,165	43,950	26,475	7,529	15,420	16,708	19,545	22,411	26,079
Other Southwest (Extrapolated Areas)										
West	90,000	8,900	24,490	16,433	0	11,094	13,455	11,094	15,000	16,433
Central	143,000	3,100	26,356	16,269	0	4,402	5,086	9,524	12,400	14,374
East	90,000	2,500	50,230	29,440	12,397	16,025	16,750	19,185	22,500	29,253
South	7,000	3,000	82,466	51,275	25,237	37,875	39,500	47,818	50,100	51,275
Total	330,000	17,500	183,542	113,417	37,634	69,396	74,791	87,621	100,000	111,335
Total Region	403,258	20,665	227,492	139,892	45,163	84,816	91,499	107,166	122,411	137,414
EASTERN REGION (EXTRAPOLATED AREAS)										
Central										
Shallow	70,000	11,500	49,297	34,851	17,111	28,952	28,951	29,067	34,600	34,847
Intermediate	160,000	15,000	38,368	25,745	0	17,321	21,080	17,381	23,500	25,745
Deep	25,000	2,500	46,212	27,084	11,406	14,293	15,410	17,650	20,700	26,913
Total	255,000	29,000	133,877	87,680	28,517	60,566	65,441	64,098	78,800	87,505
Coastal	25,000	11,000	85,424	59,782	12,172	37,180	39,442	15,925	48,400	54,395
Total Region	280,000	40,000	219,301	147,462	40,689	97,746	104,883	80,023	127,200	141,900
MID-CONTINENT REGION (EXTRAPOLATED AREAS)										
Shallow	5,000	890	3,713	2,620	1,301	2,165	2,167	2,172	2,600	2,620
Intermediate	10,000	170	1,739	1,071	0	314	341	628	800	932
Deep	5,000	940	2,612	1,753	0	1,183	1,435	1,183	1,600	1,753
Total Region	20,000	2,000	8,064	5,444	1,301	3,662	3,943	3,983	5,000	5,305
Total U.S.	1,014,458	121,541	924,784	607,808	192,084	365,214	403,744	331,185	503,289	574,614

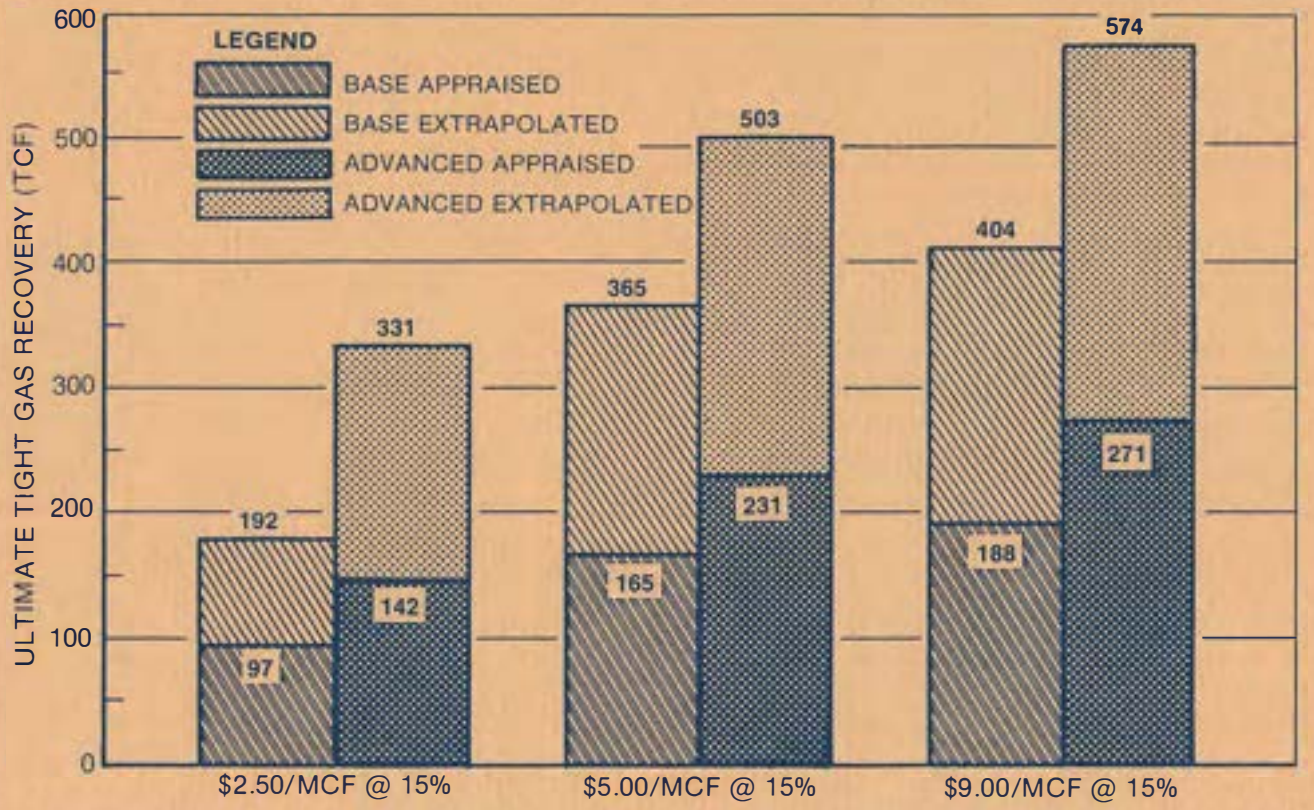


Figure 10. Total United States.

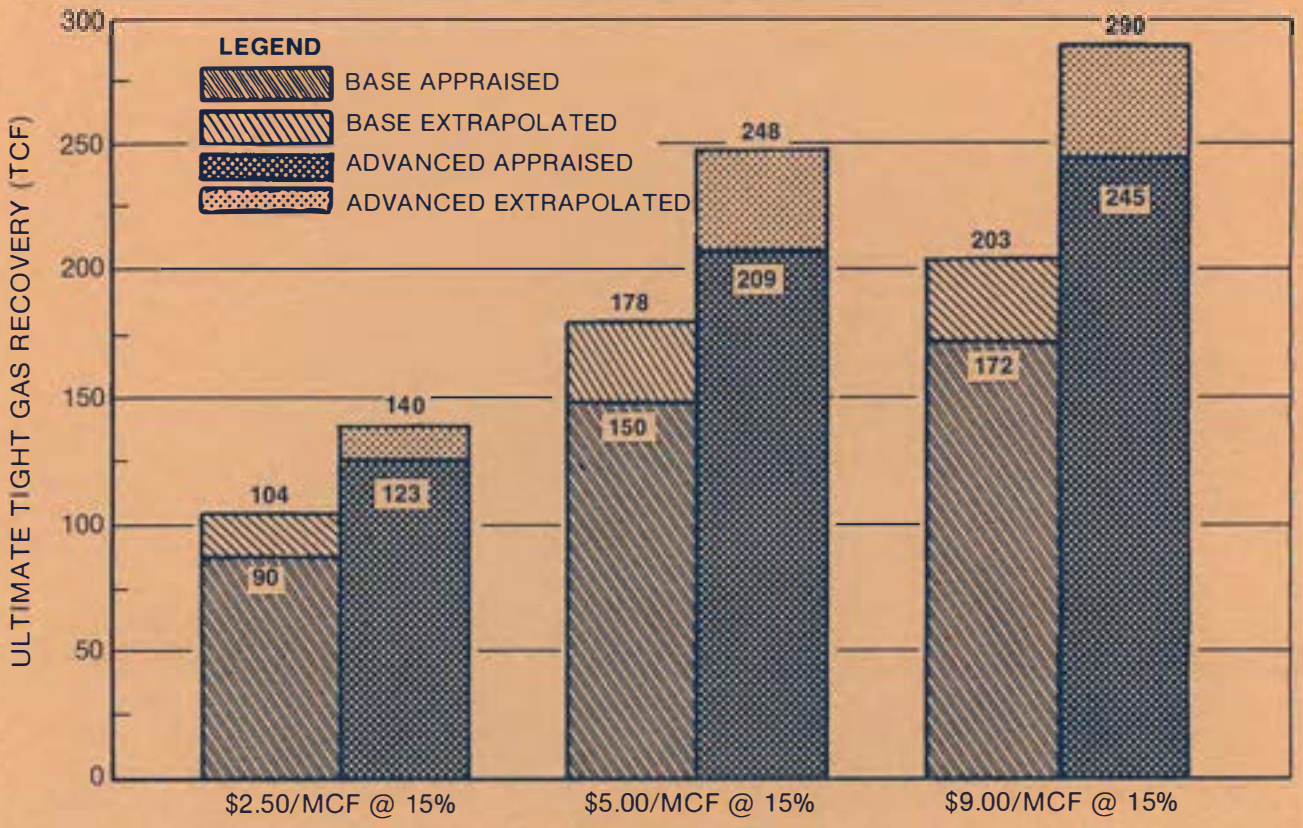


Figure 11. Western Region.

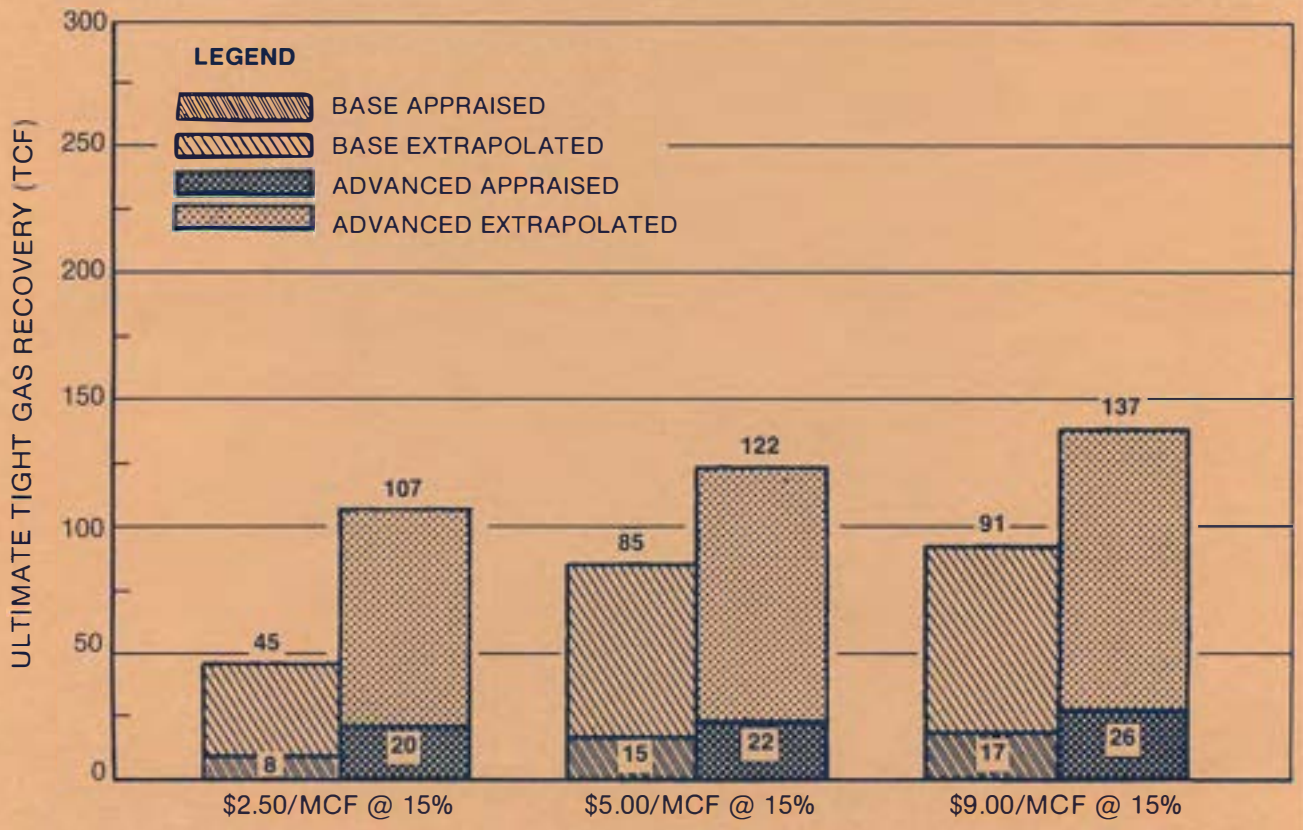


Figure 12. Greater Southwest Region.

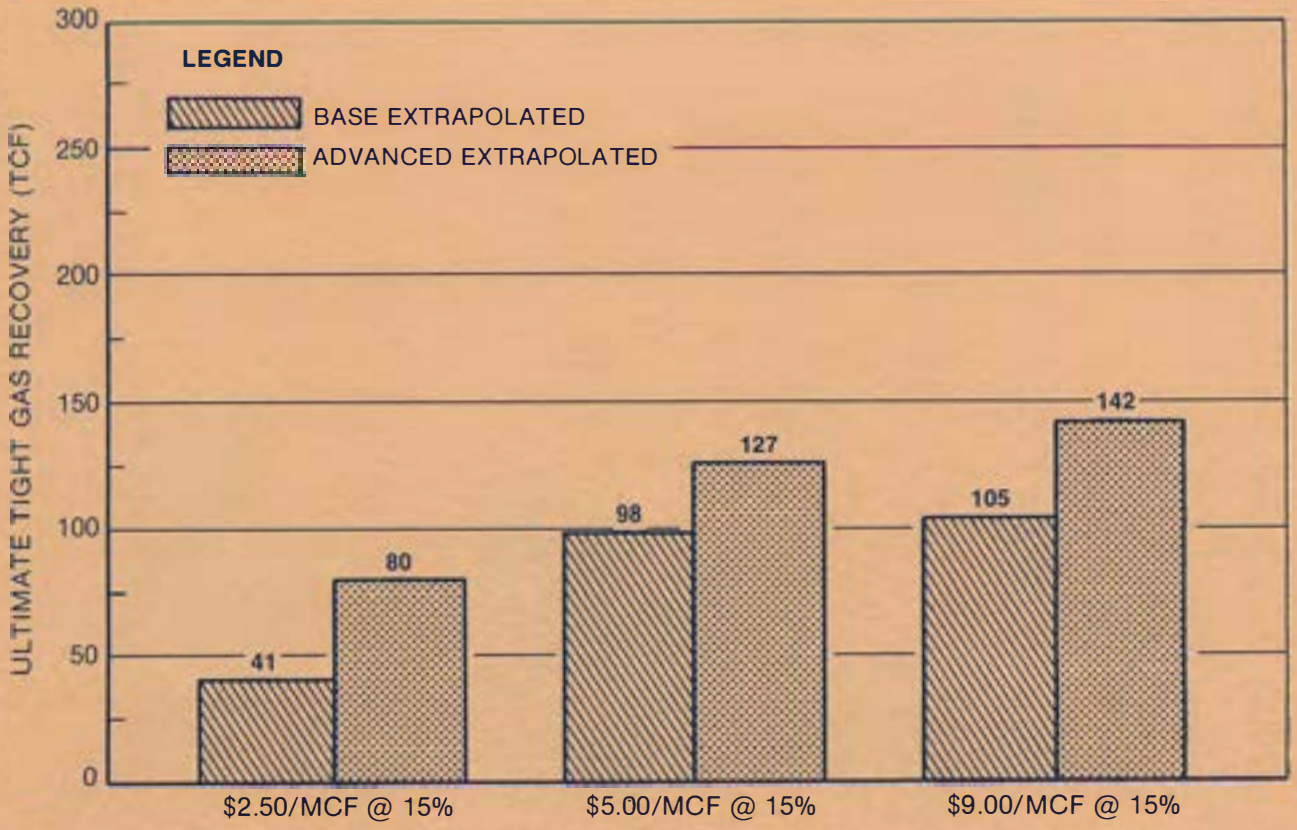


Figure 13. Eastern Region (Extrapolation Only).

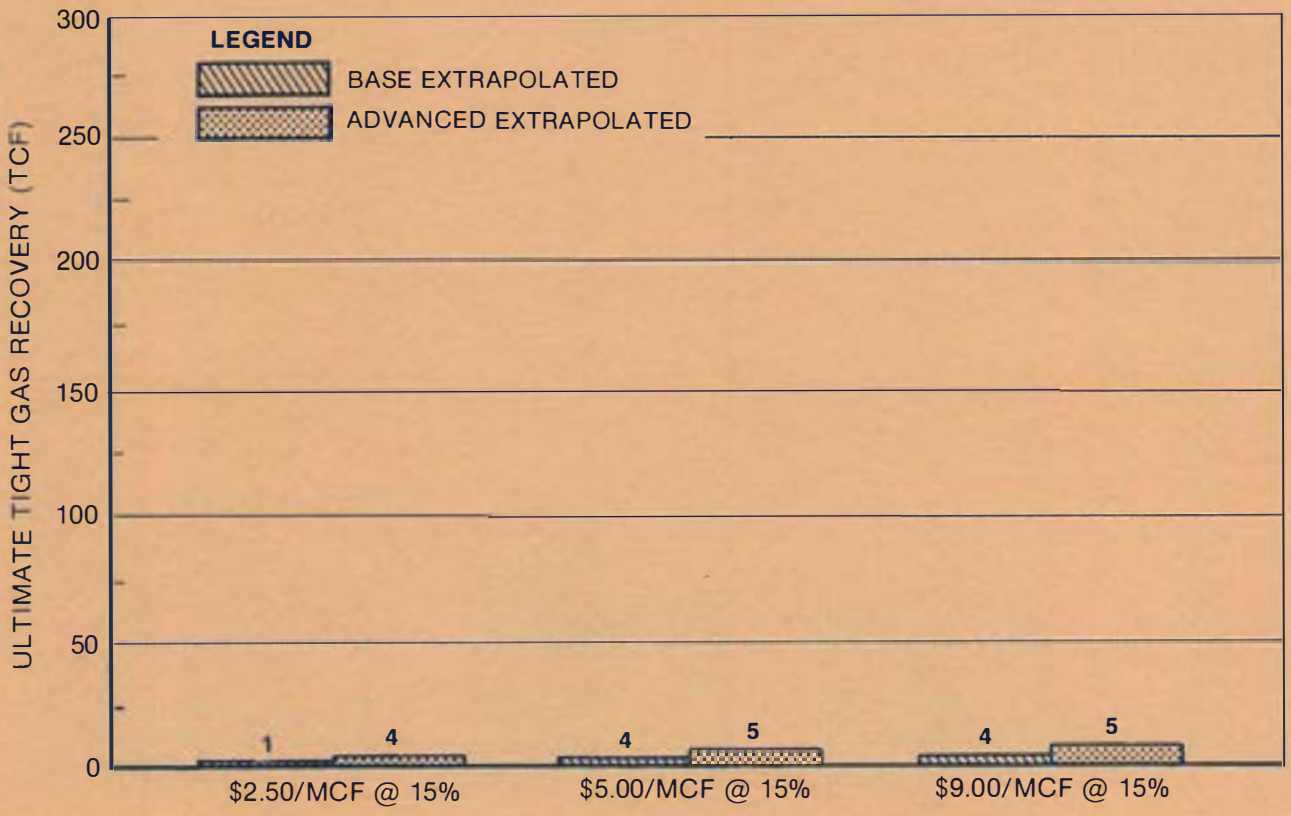


Figure 14. Mid-Continent (Extrapolation Only).

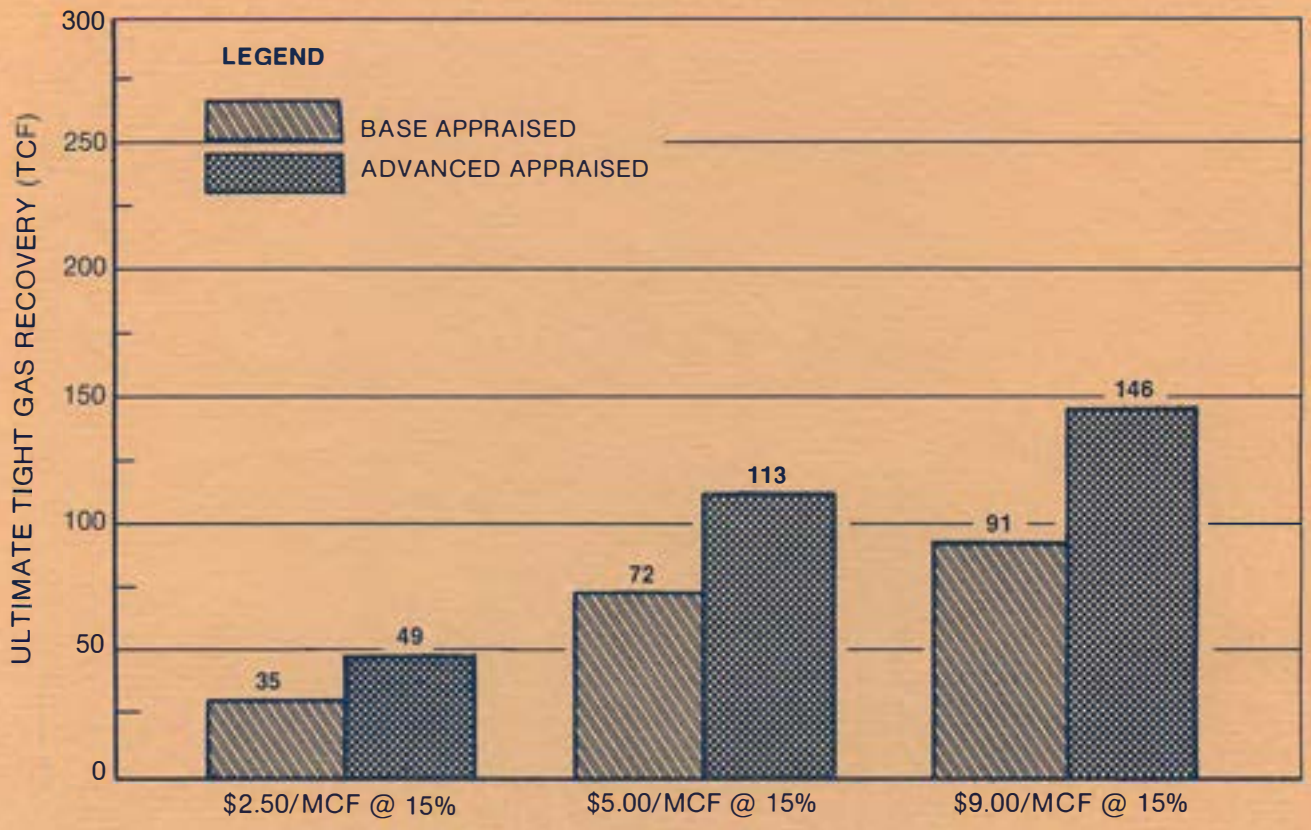


Figure 15. Rocky Mountain Appraised.

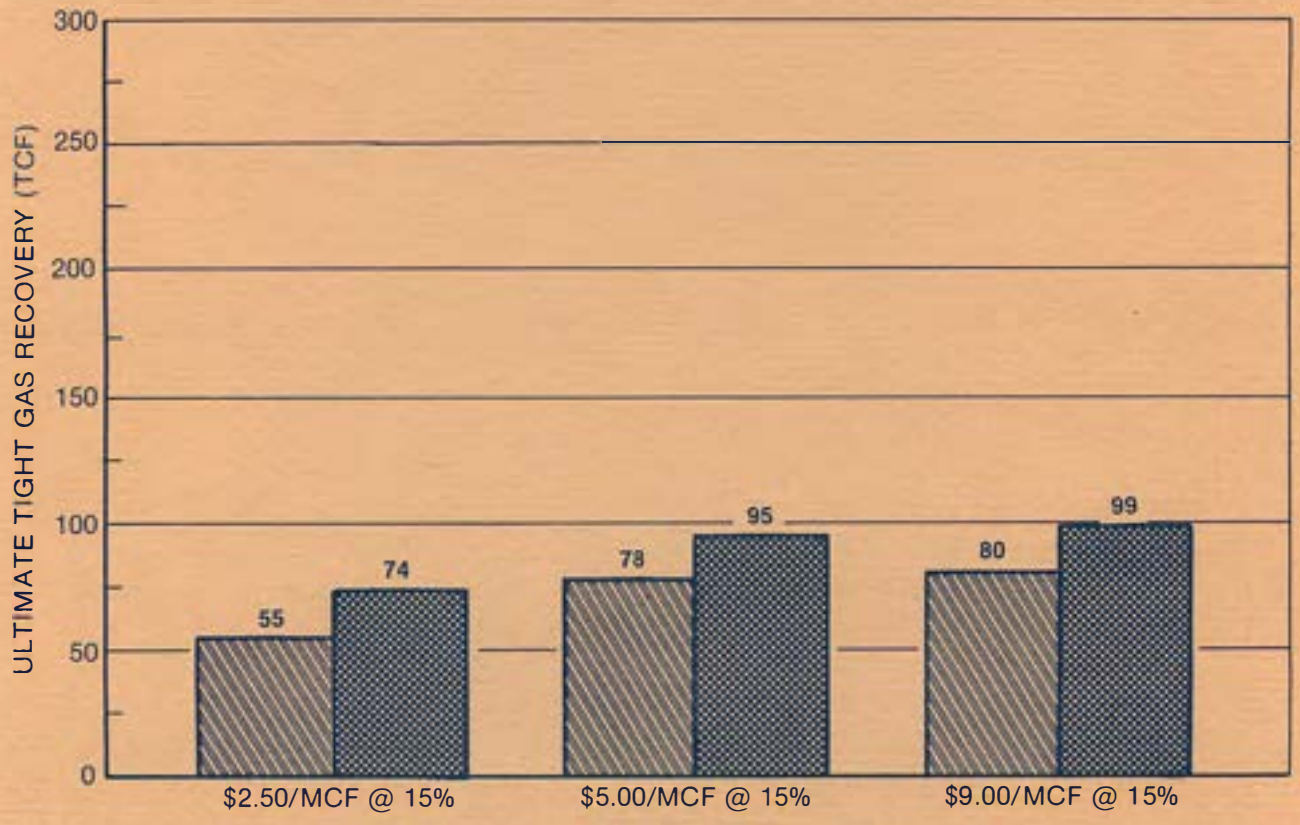


Figure 16. Northern Great Plains/Williston Appraised.

TABLE 9

Formation and Subbasin Summary of Tight Gas Resource

	Prospective Area (Sections)	Productive Area (Sections)	Estimated GIP (BCF)	Maximum Rec. Gas (BCF)	BCF Recoverable at Technology and Price (15% DCF ROR)					
					Base			Advanced		
					$2.50	$5.00	$9.00	$2.50	$5.00	$9.00
WESTERN REGION										
Northern Great Plains/Williston										
Mowry		1,228	1,733	1,298	0	614	1,054	0	937	1,298
Mowry, Greenhorn		1,031	3,007	2,221	1,667	2,021	2,022	1,998	2,221	2,221
Mowry, Carlile		1,165	4,703	3,522	2,755	3,037	3,037	3,487	3,522	3,522
Mowry, Greenhorn, Carlile		2,600	14,109	10,331	8,365	9,041	9,062	10,255	10,331	10,331
Mowry, Greenhorn, Carlile, Eagle		2,272	26,602	12,165	8,926	10,091	10,127	9,358	12,165	12,165
Mowry, Greenhorn, Eagle		1,832	7,391	5,386	3,728	4,180	4,192	4,023	5,327	5,386
Mowry, Judith River		2,361	6,657	4,836	0	4,082	4,097	3,785	4,836	4,836
Mowry, Carlile, Eagle		1,602	10,161	7,391	5,215	5,917	5,933	5,580	7,391	7,391
Mowry, Carlile, Eagle, Judith River		2,115	16,618	11,966	7,843	9,038	9,067	8,764	11,842	11,966
Mowry, Carlile, Judith River		1,256	6,212	4,514	3,313	3,682	3,694	4,466	4,514	4,514
Greenhorn		2,250	3,013	2,245	0	1,670	1,906	0	2,041	2,216
Greenhorn, Carlile		460	1,635	1,188	921	998	1,000	987	1,188	1,188
Greenhorn, Eagle		1,431	5,541	4,036	2,747	3,143	3,155	2,934	3,984	4,036
Greenhorn, Carlile, Eagle		804	4,635	3,353	2,397	2,695	2,708	2,596	3,310	3,353
Carlile		2,700	5,428	3,945	0	2,862	3,116	0	3,196	3,945
Niobrara		1,283	9,423	7,095	0	6,843	6,843	7,091	7,091	7,091
Carlile, Eagle		815	3,257	2,186	1,202	1,623	1,623	1,589	2,156	2,186
Judith River		3,910	4,288	3,093	0	0	1,480	0	0	2,281
Mowry, Greenhorn, Carlile, Eagle, Judith River		870	8,155	5,934	3,392	3,672	3,681	4,546	5,872	5,934
Carlile, Niobrara		745	5,179	3,481	2,260	2,518	2,525	2,530	3,434	3,481
Basin Total	188,900	32,730	147,747	100,186	54,731	77,727	80,322	73,989	95,358	99,341

TABLE 9 (Continued)

	Prospective Area (Sections)	Productive Area (Sections)	Estimated GIP (BCF)	Maximum Rec. Gas (BCF)	BCF Recoverable at Technology and Price (15% DCF ROR)					
					Base			Advanced		
					$2.50	$5.00	$9.00	$2.50	$5.00	$9.00
WESTERN REGION										
Greater Green River										
Area 1										
Almond A	51	443	307	225	286	294	291	307	307	
Ericson, Rock Springs, Blair	276	5,181	3,180	0	0	1,202	0	1,609	2,090	
Fort Union	191	2,564	1,701	0	729	783	0	1,475	1,670	
Almond A + Almond B	90	1,656	1,156	1,059	1,092	1,092	1,156	1,156	1,156	
Almond A + Ericson, Rock Springs, Blair	85	3,005	1,854	0	1,204	1,204	1,664	1,854	1,854	
Almond B + Ericson, Rock Springs, Blair	215	6,254	3,855	0	1,856	2,090	0	3,148	3,839	
Lance, Lewis	267	2,604	1,787	0	992	1,102	0	1,389	1,787	
Subbasin Total	1,175	21,707	13,840	1,284	6,159	7,767	3,111	10,938	12,703	
Area 2 & 3										
Almond A	436	2,064	1,465	0	709	1,231	1,101	1,326	1,465	
Almond B	228	1,937	1,247	0	770	838	0	975	1,156	
Ericson, Rock Springs, Blair	1,142	21,612	13,301	0	4,085	5,046	0	6,700	9,164	
Fort Union	142	1,851	1,226	0	540	578	0	1,078	1,207	
Almond A + Almond B	187	2,618	1,687	1,349	1,660	1,660	1,687	1,687	1,687	
Almond B + Ericson, Rock Springs, Blair	416	11,676	7,214	0	3,358	3,740	0	5,952	7,214	
Lance, Lewis	727	6,877	5,092	0	2,699	2,998	0	4,404	4,717	
Subbasin Total	3,278	48,635	31,232	1,349	13,821	16,091	2,788	22,122	26,610	
Washakie										
Almond	27	221	159	0	139	154	159	159	159	
Lance, Lewis	192	2,322	1,823	0	623	762	0	463	1,509	
Lower Mesaverde	285	7,079	4,401	0	0	1,737	0	0	3,176	
Lance, Lewis + Almond	48	1,017	735	443	651	651	735	735	735	
Lower Mesaverde + Almond	75	2,573	1,608	0	1,307	1,369	1,194	1,608	1,608	
Subbasin Total	627	13,212	8,726	443	2,720	4,673	2,088	2,965	7,187	

TABLE 9 (Continued)

	Prospective Area (Sections)	Productive Area (Sections)	Estimated GIP (BCF)	Maximum Rec. Gas (BCF)	BCF Recoverable at Technology and Price (15% DCF ROR)					
					Base			Advanced		
					$2.50	$5.00	$9.00	$2.50	$5.00	$9.00
WESTERN REGION										
Greater Green River (Continued)										
E/2 Area 4										
Mesaverde		305	6,854	4,290	0	0	1,832	0	1,235	3,942
Fort Union		178	3,756	2,298	0	688	886	0	1,367	2,070
Fort Union + Mesaverde		34	1,459	918	0	368	385	0	858	917
Subbasin Total		517	12,069	7,506	0	1,056	3,103	0	3,460	6,929
W/2 4, Bridger, Lewin 5										
Fort Union		321	4,751	2,877	0	0	978	0	1,695	2,489
Mesaverde, Lance		1,104	12,872	7,544	0	0	3,425	0	0	5,004
Frontier		783	7,390	4,921	0	3,439	4,349	3,439	4,737	4,737
Mesaverde, Lance + Frontier		138	2,734	1,809	0	1,237	1,622	0	1,809	1,809
Fort Union + Mesaverde, Lance		138	3,702	2,177	0	722	937	0	1,454	2,067
Subbasin Total		2,484	31,449	19,328	0	5,398	11,311	3,439	9,695	16,106
Sandwash										
Lewis 7,000		237	1,334	925	0	674	752	925	925	925
Lewis 9,000		263	1,962	1,304	0	721	900	0	1,304	1,304
Mesaverde 9,000		143	2,038	1,307	0	0	505	0	0	848
Mesaverde 11,000		169	2,565	1,648	0	0	670	0	0	1,092
Lewis 7,000 + Mesaverde 9,000		26	537	344	0	205	225	0	335	344
Mesaverde 9,000 + Mesaverde 11,000		19	560	357	0	0	159	0	256	329
Subbasin Total		857	8,996	5,885	0	1,600	3,211	925	2,820	4,842
Basin Total	28,300	8,938	136,068	86,517	3,076	30,754	46,156	12,351	52,000	74,377

TABLE 9 (Continued)

	Prospective Area (Sections)	Productive Area (Sections)	Estimated GIP (BCF)	Maximum Rec. Gas (BCF)	BCF Recoverable at Technology and Price (15% DCF ROR)					
					Base			Advanced		
					$2.50	$5.00	$9.00	$2.50	$5.00	$9.00
WESTERN REGION										
Wind River										
Lower Fort Union		630	6,969	5,115	3,355	3,709	3,709	3,677	5,115	5,115
Lance 9,000		180	2,303	1,740	0	860	918	0	1,172	1,642
Lance 14,000		270	5,230	3,306	0	1,200	1,687	0	1,778	2,495
Mesaverde 15,000		270	4,425	2,744	0	0	0	0	0	0
Lower Fort Union + Lance 9,000		270	6,218	4,800	2,789	2,971	2,971	3,718	4,800	4,800
Lance 14,000 + Mesaverde 15,000		180	6,519	4,034	0	0	1,279	0	0	3,179
Frontier/Muddy		480	2,035	1,547	895	1,111	1,163	1,377	1,547	1,547
Basin Total	7,400	2,280	33,699	23,286	7,039	9,851	11,727	8,772	14,412	18,778
Uinta										
Coaly		102	1,617	1,155	1,031	1,079	1,079	1,155	1,155	1,155
Castlegate		180	1,673	1,131	0	835	979	1,060	1,131	1,131
Coaly + Castlegate		77	2,003	1,359	1,359	1,359	1,359	1,359	1,359	1,359
Wasatch + Coaly		96	3,069	2,199	2,067	2,067	2,067	2,199	2,199	2,199
Wasatch + Barren		105	2,756	2,099	1,986	1,986	1,986	2,099	2,099	2,099
Wasatch		428	6,304	5,017	4,105	4,105	4,105	4,833	5,017	5,017
Barren		196	3,043	2,309	1,672	1,805	1,805	2,054	2,309	2,309
Basin Total	9,500	1,184	20,465	15,269	12,220	13,236	13,380	14,759	15,269	15,269
Piceance										
Corcoran Cozette		369	3,193	2,294	1,291	1,865	1,884	2,216	2,294	2,294
Fort Union		354	3,088	2,097	0	1,077	1,077	0	1,630	1,630
Mesaverde 8,000		1,443	30,544	20,155	8,047	9,851	10,467	5,579	15,079	17,413
Corcoran Cozette + Mesaverde		180	5,306	3,509	2,288	2,665	2,665	3,224	3,509	3,509
Fort Union + Mesaverde		101	3,085	2,040	772	1,029	1,072	1,214	1,619	1,981
Fort Union + Corcoran Cozette		51	826	596	475	482	482	596	596	596
Lower Cretaceous, Jurassic		646	3,101	2,288	0	1,454	1,775	0	1,700	2,288
Basin Total	7,100	3,144	49,143	32,979	12,873	18,423	19,422	12,829	26,427	29,711
Denver										
Area A		1,100	9,175	5,539	0	0	1,039	0	4,518	5,539
Area B		500	4,109	2,379	0	0	127	0	694	2,057
Basin Total	45,000	1,600	13,284	7,918	0	0	1,166	0	5,212	7,596

TABLE 9 (Continued)

		Prospective Area (Sections)	Productive Area (Sections)	Estimated GIP (BCF)	Maximum Rec. Gas (BCF)	BCF Recoverable at Technology and Price (15% DCF ROR) Base $2.50	Base $5.00	Base $9.00	Advanced $2.50	Advanced $5.00	Advanced $9.00
GREATER SOUTHWEST											
San Juan		12,500	1,188	3,298	2,213	0	1,494	1,812	1,494	2,020	2,213
Val Verde - Ozona Trend		15,300	150	1,024	638	0	106	182	370	532	604
Val Verde - Sonora Trend		7,700	350	3,507	2,160	0	633	688	1,267	1,613	1,879
Edwards Lime Trend											
Southwest			189	5,005	3,171	2,142	2,391	2,423	2,958	3,098	3,171
Central			261	9,249	5,477	0	3,820	4,311	5,104	5,353	5,477
Basin Total		858	450	14,254	8,648	2,142	6,211	6,734	8,062	8,451	8,648
Cotton Valley Trend		36,900	1,027	21,867	12,816	5,387	6,976	7,292	8,352	9,795	12,735
Total U.S. Appraised		359,458	53,041	443,776	292,603	97,468	165,411	188,881	142,245	231,089	271,151
Other Western (Extrapolated Areas)											
Shallow											
Type 4 - Fmn Type	1107	7,300	2,300	8,024	6,100	3,529	4,381	4,586	5,430	6,100	6,100
Intermediate											
Type 4 - Fmn Type	1101	3,100	800	8,720	6,400	4,198	4,641	4,641	4,601	6,400	6,400
Type 6 - Fmn Type	1301		800	5,428	3,900	2,195	3,171	3,203	3,767	3,900	3,900
	1302		1,200	9,283	6,304	0	3,238	3,238	0	4,900	4,900
	1303		1,000	19,243	12,698	5,070	6,206	6,594	3,515	9,500	10,970
	1307		2,200	10,580	7,806	0	4,961	6,056	0	5,800	7,806
Total Type 6		12,600	5,200	44,534	30,708	7,265	17,576	19,091	7,282	24,100	27,576
Total Intermediate		15,700	6,000	53,254	37,108	11,463	22,217	23,732	11 883	30,500	33,976
Deep											
Type 4 - Fmn Type	2502		400	3,537	2,672	0	1,321	1,410	0	1,800	2,602
	2503		300	4,700	2,975	0	1,080	1,518	0	1,600	2,245
Total Deep		2,000	700	8,243	5,647	0	2,401	2,928	0	3,400	4,847
Total Western Extrapolated		25,000	9,000	69,521	48,855	14,992	28,999	31,246	17,313	40,000	44.923

TABLE 9 (Continued)

	Prospective Area (Sections)	Productive Area (Sections)	Estimated GIP (BCF)	Maximum Rec. Gas (BCF)	BCF Recoverable at Technology and Price (15% DCF ROR)					
					Base			Advanced		
					$2.50	$5.00	$9.00	$2.50	$5.00	$9.00
Other Southwest (Extrapolated Areas)										
West										
Type 8 - Fmn Type 1601	90,000	8,900	24,490	16,433	0	11,094	13,455	11,094	15,000	16,433
Central										
Type 9 - Fmn Type 2301	35,000	800	4,620	2,878	0	478	821	1,669	2,400	2,725
Type 10 - Fmn Type 1801	108,000	2,300	21,736	13,391	0	3,924	4,265	7,855	10,000	11,649
Total Central	143,000	3,100	26,356	16,269	0	4,402	5,086	9,524	12,400	14,374
East										
Type 12 - Fmn Type 2101	90,000	2,500	50,230	29,440	12,397	16,025	16,750	19,185	22,500	29,253
South										
Type 11 - Fmn Type 2201	5,000	2,300	58,968	37,360	25,237	28,170	28,547	34,851	36,500	37,360
2202	2,000	700	23,498	13,915	0	9,705	10,953	12,967	13,600	13,915
Total South	7,000	3,000	82,466	51,275	25,237	37,875	39,500	47,818	50,100	51,275
Total Southwest Extrapolated	330,000	17,500	183,542	113,417	37,634	69,396	74,791	87,621	100,000	111,335

TABLE 9 (Continued)

		Prospective Area (Sections)	Productive Area (Sections)	Estimated GIP (BCF)	Maximum Rec. Gas (BCF)	BCF Recoverable at Technology and Price (15% DCF ROR)					
						Base			Advanced		
						$2.50	$5.00	$9.00	$2.50	$5.00	$9.00
Eastern (Extrapolated Areas)											
Central											
Shallow											
Type 1 - Fmn Type	1202		4,000	11,102	8,200	6,155	7,462	7,465	7,377	8,200	8,200
	1217		1,500	11,295	8,504	0	8,203	8,203	8,500	8,500	8,500
	1218		3,500	12,387	8,314	4,572	6,173	6,173	6,044	8,200	8,314
	1220		2,500	14,513	9,833	6,384	7,113	7,132	7,146	9,700	9,833
Total Shallow		70,000	11,500	49,297	34,851	17,111	28,951	28,973	29,067	34,600	34,847
Intermediate											
Type 8 - Fmn Type	1601	160,000	15,000	38,368	25,745	0	17,381	21,080	17,381	23,500	25,745
Deep											
Type 12 - Fmn Type	2101	25,000	2,500	46,212	27,084	11,406	14,743	15,410	17,650	20,700	26,913
Total Central		255,000	29,000	133,877	87,680	28,517	60,566	65,463	64,098	78,800	87,505
Coastal											
Type 6 - Fmn Type	1301		2,000	18,095	13,000	7,316	10,569	10,667	12,558	13,000	13,000
	1302		3,000	24,818	16,853	0	8,656	8,656	0	13,100	13,100
	1303		1,000	18,433	12,163	4,856	5,945	6,317	3,367	9,100	10,529
	1307		5,000	24,078	17,766	0	11,290	13,782	0	13,200	17,766
Total Coastal		25,000	11,000	85,424	59,782	12,172	37,180	39,442	15,925	48,400	54,395
Total Eastern Extrapolated		280,000	40,000	219,301	147,462	40,689	97,746	104,883	80,023	127,200	141,900

TABLE 9 (Continued)

		Prospective Area (Sections)	Productive Area (Sections)	Estimated GIP (BCF)	Maximum Rec. Gas (BCF)	BCF Recoverable at Technology and Price (15% DCF ROR)					
						Base			Advanced		
						$2.50	$5.00	$9.00	$2.50	$5.00	$9.00
Mid-Continent (Extrapolated)											
Shallow											
Type 1 - Fmn Type	1202		310	812	600	450	546	546	540	600	600
	1217		120	797	600	0	579	579	600	600	600
	1218		300	1,057	710	390	527	527	516	700	710
	1220		160	1,047	710	461	513	515	516	700	710
Total Shallow		5,000	890	3,713	2,620	1,301	2,165	2,167	2,172	2,600	2,620
Intermediate											
Type 10 - Fmn Type	1801	5,000	170	1,739	1,071	0	314	341	628	800	932
Deep											
Type 8 - Fmn Type	1601	10,000	940	2,612	1,753	0	1,183	1,435	1,183	1,600	1,753
Total Mid-Continent Extrapolated		20,000	2,000	8,064	5,444	1,301	3,662	3,943	3,983	5,000	5,305
Total U.S. Extrapolated		655,000	68,500	480,428	315,178	94,616	199,803	214,863	188,940	272,200	303,463

TABLE 10

Formations Included in Appraised Study

Basin	Formations	
	Name	Type
Northern Great Plains/Williston	Judith River	Blanket
	Niobrara	Blanket
	Eagle	Blanket
	Carlile	Blanket
	Green Horn	Blanket
	Mowry	Blanket
Greater Green River	Fort Union	Lenticular
	Mesaverde	Lenticular
	Lance & Lewis	Lenticular
	Lewis 7,000	Blanket
	Lewis 9,000	Blanket
	Almond A	Blanket
	Almond B	Lenticular
	Ericson	Lenticular
	Rock Springs	Lenticular
	Blair	Lenticular
	Frontier	Blanket
Wind River	Fort Union	Lenticular
	Lance	Lenticular
	Lower Mesaverde	Lenticular
	Frontier/Muddy	Blanket
Uinta	Wasatch	Lenticular
	Barren	Lenticular
	Coaly	Blanket
	Castlegate	Blanket
Piceance	Fort Union	Lenticular
	Corcoran Cozette	Blanket
	Mesaverde	Lenticular
	Lower Cretaceous Jurassic	Lenticular
Denver	Lower Cretaceous	Blanket
San Juan	Dakota	
Val Verde (Ozona/Sonora)	Ozona	Blanket
	Sonora	Blanket
	Epps-Ray	Blanket
Edwards Lime	Edwards Southwest	Blanket
	Edwards Central	Blanket
Cotton Valley	Cotton Valley	Blanket

of these overlapping formations was used to appraise the potential resource. The designation for the areas included as "extrapolated areas" are listed in such a way as to reflect the corresponding type of basin or formation which was used from the detailed appraisals for extrapolation. A list of the corresponding formations is tabulated in Table 11. The chapters covering each basin in Part II of this report give resource and economic data for prices of from $1.50 to $12.00/MCF.

TABLE 11

Extrapolated Area Formation and Basin Characteristics

Basin Denotation	Formation or Basin Geological and Reservoir Characteristics Used for Extrapolation Purposes
Type 1	Northern Great Plains/Williston
Type 4	Wind River
Type 6	Piceance
Type 8	San Juan
Type 9	Val Verde-Ozona Trend
Type 10	Val Verde-Sonora Trend
Type 11	Edwards Lime Trend
Type 12	Cotton Valley Trend
Formation Denotation	
Formation Type 1101	Wind River Lower Fort Union
Formation Type 1107	Wind River Frontier, Muddy
Formation Type 1202	NGP-Mowry + Greenhorn
Formation Type 1217	NGP-Niobrara
Formation Type 1218	NGP-Carlile + Eagle
Formation Type 1220	NGP-Carlile + Niobrara
Formation Type 1301	Piceance Corcoran Cozette
Formation Type 1302	Piceance Fort Union
Formation Type 1303	Piceance Mesaverde 8,000
Formation Type 1307	Piceance Lower Cretaceous Jurassic
Formation Type 1601	San Juan Dakota
Formation Type 1801	Val Verde-Sonora
Formation Type 2101	Cotton Valley
Formation Type 2201	Edwards Lime Southwest
Formation Type 2202	Edwards Lime Central
Formation Type 2301	Val Verde-Ozona
Formation Type 2502	Wind River Lance 9,000
Formation Type 2503	Wind River Lance 14,000

Tables E-11 and E-12 in Appendix E show the amount of recoverable resources in each appraised formation as determined by price and technology, at rates of return of 10 percent and 20 percent, respectively.

Comments on the Total U.S. Estimate and the Extrapolated Values

Several approaches were considered for estimating the size of the total U.S. tight gas resource. They resulted in a variety of estimates and reiterated the need for a formation-by-formation evaluation in all of the 113 basins and additional speculative areas. The discussion which follows summarizes the approach taken by the study participants to arrive at an estimate for the entire lower 48 states.

After the detailed appraisals were completed, the study participants made their individual estimates of the total U.S. recoverable tight gas. Estimates at gas prices in the range of $2.50 to $9.00/MCF varied from 295 to 700 TCF, with an average of 510 TCF. A probability plot of the estimates gives 500 TCF as the expected value for the group. The average for the various regions estimated by individuals in the group is shown in Table 12.

TABLE 12

Individual Estimates
(TCF)

	Range	Average
United States	295 - 700	510
Rocky Mountains	80 - 250	117
Northern Great Plains	10 - 130	96
Southwest	22 - 75	30
Greater Southwest	80 - 175	116
Other U.S.	75 - 287	162

The estimate of 503 TCF for the total U.S. tight gas resource (at $5.00/MCF and a 15 percent DCF ROR) represents the final consensus of the study group. This estimate includes the 231 TCF determined from the detailed appraised study plus 272 TCF attributed to the extrapolated areas (both representing recoveries at $5.00/MCF and a 15 percent DCF ROR).

Because of the paucity of experience and available data it was necessary to use typical geological characteristics from the appraised studies to estimate the tight gas resource for the extrapolated areas. The extrapolated values attributed to each region were determined from estimates of geological-type basins and formations assigned to that region (the correlative basins and formations are denoted in Table 11). For example, in the Eastern region

it was estimated that basins similar to the Northern Great Plains (Type 1), Piceance (Type 6), San Juan (Type 8), and Cotton Valley (Type 12) would cover a prospective area of 280,000 sections. In each basin type, formation types would exist which were similar to formations existing in the appraised areas. Again referring to the Eastern region, in the central deep areas, formations similar to the Cotton Valley (Formation Type 2101) would cover approximately 25,000 sections. The estimates of gas in place, maximum recoverable gas, and economically recoverable gas for each region (based on both price and technology) were commensurate with the apportionment of geological types assigned to each region. The values listed in Table 13 summarize the approximations which can be used to reconcile geological prospective and productive areas with gas in place. The data in Table 9 for the respective appraised formations can be used to reconcile the recoverable gas values estimated for the extrapolated areas.

The Potential Gas Committee has been estimating the total undiscovered gas potential of the United States for 14 years. Included with the 1978 report of the Potential Gas Committee was a discussion by the Potential Gas Agency of the unconventional gas resource for a specific set of basins. In the 1980 report, the Potential Gas Agency plans to discuss unconventional gas again as a separate item for a limited number of basins. It is anticipated that the Committee will continue to make these estimates every two years. At the same time, operators in tight gas areas are submitting reservoir data to state regulatory agencies as a part of FERC's incentive price program. These data, which are a matter of public record, will gradually accumulate until a better estimate of the tight gas resource can be made.

In the meantime, the study participants had an immediate need for an estimate of the total resource; this is the basis for projecting the production rate of tight gas for the next 20 years. Production rates will not always correspond with the size of the resource: if the resource is small, the production rates will also be small, but if it is large, the production rates will not necessarily be sensitive to its absolute size.

As was previously stated, estimates of the tight gas resource size (summarized in Table 14) will vary depending upon the method used. The approach taken by the study group represents their best effort to arrive at a realistic estimate.

TABLE 13

Percentage of Basin Area Containing Tight Gas

Basin	Number of Sections in Basin*	Number of Sections Probably Productive of Tight Gas	Percentage of Basin Productive of Tight Gas	Average Resources BCF/Section of Productive Area†
Val Verde - Sonora and Ozona Trends	23,000	500	2.2	5.6
Cotton Valley	36,900	1,027	2.8	12.5
Denver	45,000	1,600	3.6	4.9
San Juan	12,500	1,188	9.5	1.9
Uinta	9,500	1,184	12.5	12.9
Northern Great Plains/Williston	188,900	32,730	17.3	3.1
Wind River	7,400	2,280	30.8	10.2
Greater Green River	28,300	8,938	31.6	9.7
Piceance	7,100	3,144	44.3	10.5
Edwards Lime Trend	858	450	52.4	19.2
Total	359,458	53,041	14.8	5.5

*Basin areas reflect the gross area of the basins. The somewhat smaller area listed in the basin chapters reflects the probable sedimentary portion of the basins.

†From Table 9 showing maximum recoverable gas resource (see basin chapters of Part II of this report for details).

TABLE 14

Estimates of U.S. Tight Gas by Various Approaches
(TCF)

Approach	Range	Best Value
Detailed Appraisal and Extrapolation	192 - 574	503
Study Participant Ballot	295 - 700	500

Chapter Three

METHOD USED TO APPRAISE RESOURCE SIZE, PRODUCTION RATES, AND ULTIMATE RECOVERABLE GAS

METHODS OF ANALYSIS

Resource Estimates

Resource estimates for this study were developed from basic data provided by members participating in the study effort. Teams of geologists and engineers with considerable expertise on one or more of the 12 basins analyzed and appraised in detail for this study provided data describing the distribution of gas porosity, productive area, net pay, and in situ effective gas permeability for the respective basins. For each basin, the following general procedure was used to arrive at estimates for the tight gas resource size, the maximum recoverable gas, and the effects of technology, cost, and gas price on economically recoverable gas:

- Geological Functions
  - Select basin prospective area
  - List exploration and lease costs
  - Select target formation(s)
  - List permeability levels, percentage of area
  - List net pay, porosity, pressure, depth, temperatures
  - Estimate field sizes
  - Estimate wildcat success ratio.
- Engineering Functions
  - Run production simulator model for initial production rate, decline rate, and 30-year ultimate per well for each permeability level
  - Provide costs for drilling, surface equipment, massive fracture stimulation, and operating and overhead
  - Estimate drilling schedule for pipeline supply rate
  - Estimate NGL (barrels per million cubic feet [bbl/MMCF]).

This required compilation of data from known productive areas, both conventional and tight, and projection of these data to the undeveloped tight regions included in this study.

In-place permeabilities to gas were determined from well performance over an extended production period in known tight gas areas. These data were projected to the prospective tight gas areas for the formations in the 12 basins studied. Log and core data were used to establish in situ gas porosity values and net pay thickness associated with various permeability levels for each of the 48 tight gas formations analyzed. A range of permeabilities was established for each formation. These were the average vertical permeabilities over the net pay thickness, estimated from well data. These average permeabilities varied horizontally areawise across the basin.

The teams estimated the number of productive sections for each formation in all 12 basins. Only areas not yet producing tight gas were considered, as the objective of this study is to estimate new potential reserve additions. For each permeability level the number of areal sections (square miles), and the net pay, porosity, gas in place, recovery factor, and ultimate recovery were determined.

Estimates of the percentage of prospects productive as a function of permeability were provided for each formation of each basin by the geologists, who also provided field size distributions for each formation and permeability.

Recovery Factors

The gas in place was calculated based on the assumptions of a uniform average porosity, temperature, and pressure throughout the gas field discovered. Using these same assumptions, the gas that would remain if the pressure in the formation were reduced to the well bore drawdown pressure (i.e., about one tenth the original formation pressure) was calculated. The difference between gas in place and gas that will remain at depletion is the gas that is subject to being produced under these conditions. This "potential production" was then reduced by a recovery factor, which takes into account deviations from the uniformity assumed above. This is necessary because the porosity and permeability in some parts of the field will be substantially less than average. Also, excessive clay deposits and restrictive capillary water phenomena are generally correlated with low permeability. The recovery factors assigned reflect this correlation, as indicated in Table 15.

Wells drilled in low quality areas may be designated as dry development wells. Some parts of the field area will be so affected that the gas will not flow out of the pores in a reasonable time. Once a low quality area of the field is found, it will be avoided in future development.

TABLE 15

Recovery Factors
(Adjusting for Variation From Average
Reservoir Characteristics)

Average Permeability (md)	Recovery Adjustment Factor
0.3	0.95
0.1	0.90
0.03	0.85
0.01	0.80
0.003	0.75
0.001	0.70
0.0003	0.65
0.0001	0.60
0.00003	0.55
0.00001	0.50

Blanket Sand Recovery Factor

As described above, not all of the gas in place in a blanket formation will be produced in the 30-year period studied in this report. Specific reasons for blanket sand reductions are:

- Reduction for gas remaining in formation when the pressure has declined to the well bore pressure (about 10 percent of original gas in place). The amount of gas that could be produced is called the "technically recoverable gas in place" in Table 21.

- The technically recoverable gas is reduced further by the areal nonuniformity (very tight spots) at the edges and within the field. The recovery factors in Table 15 are applied to reduce the technically recoverable gas to the maximum recoverable gas (Table 21).

- To produce this maximum recoverable gas the necessary number of wells must be drilled. The 30-year cumulative production per well (Tables 24 and 25) was used to determine the number of wells needed per section to produce all of the maximum recoverable gas. However, the lack of a knowledge of fracture azimuth and the field rules in most states limit the number of wells that can be drilled per section. At the lower permeabilities this restriction (well development factor) reduces recovery still more (Table 26).

As an example, a field in the San Juan basin, Dakota formation, having a permeability of 0.001 md would have the following reductions applied for four wells per section:

RGAW = (GIP)(APF)(RF)(WDF)

where

RGAW = recoverable gas from actual wells

GIP = gas in place per section = 2.76 BCF per section (Table 21)

APF = abandonment pressure factor = (2.50/2.76) = 0.9058 (Table 21)

RF = recovery factor = 0.70 (Table 15)

WDF = well development factor = $\frac{4}{6.6}$ = 0.606 (base case) (Table 26)

indicating a reduction in well drainage efficiency due to an inadequate number of wells in the section.

RGAW = (2.76)(0.9058)(0.70)(0.606) = 1.06 BCF per section

Therefore, only 38 percent of the gas in place will be produced.

Lenticular Sand Recovery Factor

Some reservoirs are very small -- only a few acres in extent. These usually occur in groups and are referred to as lenticular reservoirs. A well drilled into a cluster of these lenses will intersect only a small number of them. Long fractures are created for the purpose of reaching out from the well to intersect as many lenses as possible. The location of the lenses in a given horizontal plane (depth) is uncertain, as is the direction (azimuth) the fracture will take. Thus, these circumstances cause an additional reduction in the gas produced. The values for this lenticular recovery factor (LRF) are uncertain. Most industry experience is with blanket reservoirs.

The participants in this study related the LRF to a model that allowed the controllable choices of the operator and assumptions about lenses and fracture technology to alter the recovery factor. The LRF is influenced by permeability, lens thickness, lens size, fracture length, and number of wells per section.

The method used for estimating the gas production from lenticular reservoirs was based on the following assumptions:

- The lenticular reservoirs consist of groups of small sand lenses distributed at random in impermeable rock (usually horizontal layers of varying thicknesses).

- The number of lenses intersected by a fracture can be estimated by probability relationships described by Savinskii.[1]

- The lenses have the size distribution illustrated in Table 16. These size estimates represent a set of standard sizes based in part on measurements of exposed lenses in outcrops and canyon walls by Carroll F. Knutson. These sizes from the Piceance and Uinta basins were used in estimates for all lenticular formations.

- The average permeability of the set of lenses making up a single gas field is the same throughout the field.

- A fracture originating at a well will pass through the impermeable shale and through lens after lens without stopping until its intended length is reached.

- Gas will flow linearly down the lens to the fracture and through the fracture to the well.

- Fractures will cross lenses perpendicular to the length of the lens regardless of the angle of intersection of lens and fracture.

- Fractures from a set of wells in a section will tend to be parallel to one another and spaced about the same distance apart as the wells.

With these assumptions as a basis, equations and a model were derived to calculate the amount of gas production from a section of land over a 30-year period. The amount of gas produced was calculated and used in the economic analysis. The model made calculations of the percentage recovery of the recoverable gas in the section (square mile) as a function of the number of wells per section. The most economical well spacing was used for each set of reservoir properties and permeability in each gas field discovered. Recovery per well was calculated by dividing the recovery per section by the number of actual wells drilled in each section. This method was necessary for lenticular reservoirs because only part of the fracture contacts reservoir rock. In contrast, wells in blanket reservoirs are very efficient because the fracture always contacts reservoir rock.

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[1]Savinskii, Igor Dmitrievich, "Probability Tables for Locating Elliptical Underground Masses with a Rectangular Grid," IFI/Plenum Data Corp., New York, 1965. The Savinskii method used for these estimates and verified independently by three of the participants is based on the search for buried ore bodies with seismic lines.

TABLE 16

Lens Size Distribution*,†,§

Lens Height (Ft.)	Lens Width (Ft.)	Lens Length (Ft.)	Percentage of Lenses of These Sizes	
			Piceance	Other Basins (from Uinta Study)
60	1,200	6,000	0	5
40	800	4,000	7	14
32	640	3,200	5	17
26	520	2,600	25	37
19	380	1,900	63	27
			100	100
Number of Lenses in Sample			97	747

*Knutson, Carroll F., "Outcrop Study of Fracture Patterns and Sandstone Geometry, Eastern Uinta Basin, Utah. Study Results and Implications to Stimulation of Tight Gas 'Sands' in the Area." May 23, 1977, prepared for U.S. Energy Research and Development Administration Nevada Operations Office Contract EY-76-C-08-0655, Report Number NVO-655-1.

†Knutson, Carroll F., "Modeling of Noncontinuous Fort Union and Mesaverde Sandstone Reservoirs, Piceance Basin, Northwestern Colorado," Society of Petroleum Engineers Journal, August 1976, pp. 175-188.

§Knutson, Carroll F., personal communication.

When fractures (and wells) are spaced more closely the probability that each lens will be contacted by a fracture becomes larger. This is especially true of smaller lenses. The lower permeability lenses drain slowly into a single fracture. Production rate and ultimate recovery increases when closer spaced fractures allow more than one fracture to cross the lens.

As an example, recovery percentages are shown in Tables 17 and 18, which illustrate both base and advanced cases. These particular values apply to the Mesaverde formation of the Piceance basin. A different set was determined for each different formation.

The lenticular recovery factors show a gratifying increase in recovery for more wells per section. The wells are expensive and higher prices for gas are needed to pay for them. The model makes approximations that sometimes show anomalous deviations from the smooth values that might be anticipated. An example is described for the Wind River basin in Part II of this volume.

The investment cost per thousand cubic foot of gas drained from a section is less for the 4,000-foot fractures of the advanced case than for the 1,000-foot fractures of the base case. In some formations the gas produced per well is less for the wells with 4,000-foot fractures than for those with 1,000-foot fractures.

TABLE 17

Lenticular Recovery Factors --
Percentage of Total Producible Gas Recovered in 30 Years
(Base Case -- Mesaverde)

Wells/Section	1	2	3	4
Kmd:				
0.1	20	50	68	82
0.03	22	53	74	90
0.01	16	40	59	77
0.003	12	29	42	58
0.001	8	20	28	40
0.0003	5	11	17	24
0.0001	3	8	12	17
0.00003	2	5	8	11

TABLE 18

Lenticular Recovery Factors --
Percentage of Total Producible Gas Recovered in 30 Years
(Advanced Case -- Mesaverde)

Wells/Section	1	2	3	4	6	8	12
Kmd:							
0.1	43	76	90	100	100	100	100
0.03	48	80	97	100	100	100	100
0.01	35	61	78	94	100	100	100
0.003	25	43	55	70	94	100	100
0.001	17	29	38	49	71	95	100
0.0003	10	17	23	29	43	64	91
0.0001	7	12	16	21	30	46	69
0.00003	4	8	10	13	20	30	45

These recovery factors are larger than current experience might indicate for lenticular reservoirs. Those with a more pessimistic outlook would reduce the recoveries from lenticular reservoirs substantially. The assumption that 1,000-foot fractures and eventually 4,000-foot fractures can be made in the alternating sand and shale of the Mesaverde formation is doubted by some who believe that the fracture tends to stop growing when it attempts to pass from a shale into a sand formation. Others believe the fracture may become wider and deposit all the proppant in a short length. Still others believe that fractures may grow vertically through the shale rather than laterally, so that the resulting fracture in the producing zone is relatively short. Certainly in a number of cases where enough proppant was placed to make a 1,000-foot fracture, the production from the well seemed to be from a 500-foot fracture. The participants in the study postulated that eventually these partial failures would be only occasional and that good results might be expected 95 percent of the time. It was decided to disregard this 5 percent possibility of partial failure. More cautious engineers might take a more pessimistic view.

As an example, a field in the Piceance basin, Mesaverde formation, having a permeability of 0.001 md would have the following reductions applied to the gas in place if one well were drilled per section:

RGAW = (GIP)(APF)(RF)(LRF)

where

RGAW = recoverable gas from actual wells

GIP = gas in place per section = 24.96 BCF per section (Table 14-20)

APF = abandonment pressure factor = (5,950*/6,490) = 0.9168

RF = recovery factor = 0.70

LRF = Lenticular recovery factor = 0.08 (Table 17)

RGAW = (24.96)(0.9168)(0.70)(0.08) = 1.28 BCF per section

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*From Table 14-20, technically recoverable gas (5,950) = maximum recoverable gas (4,165)/recovery factor (0.7).

The 5 percent of gas in place produced by a single well per section may account in part for the pessimism of some operators about the performance of fractures in the Mesaverde. If instead four wells were drilled per section, the recovery would be:

RGAW = (24.96)(0.9168)(0.70)(0.40) = 6.41 BCF per section (Tables 12-18 and 14-23, Part II)

So, for current field rules, 26 percent of the gas in place could be produced. If a reduction in recovery for partial failures of fractures to extend to the full 1,000-foot length is desired, a probability method can be used.

If the fractures that partially fail only extend 500 feet they will contact only 500/1,000, or 0.5, of the lenses in their area. So the short lens would recover half the gas a 1,000-foot lens would [(6.41)(0.5) = 3.2 BCF per section].

Fracture Length	Probability of Occurrence	Gas Recovery (BCF/Section)	Expected Value of Recovery (BCF/Section)
1,000 feet	0.95	6.41	6.09
500 feet	0.05	3.20	0.16
	1.00		6.25

Therefore, the recovery would be reduced

$$\frac{100\ (6.41 - 6.25)}{6.41} = 2.5 \text{ percent}$$

by the partial failure of some fractures to extend full length.

If advanced technology were available the recovery would change as follows using eight wells per section:

RGAW = (24.96)(0.9168)(0.70)(0.95) = 15.2 BCF per section

where

LRF = 0.95 (Table 18)

So 61 percent of the gas in place would be produced in contrast to 26 percent with current technology.

Production Rates and Evaluation Methods

The annual production rate (MMCF per well per year) and the cumulative production were calculated for 30 years by the method described in Appendix C. This method was checked and its validity was verified by various engineering members participating in the study.

The calculation method could simulate production from either a blanket-type reservoir or a lenticular formation. In either case it represented the behavior of a reservoir containing a vertical, conductive fracture starting on opposite sides of a well bore and penetrating deeply into the formation. An example of this is shown

in Figure 17. This shows the two fractures, one of which represents the case for blanket formations, and the other a typical fracture in a lenticular formation. In many cases there is just one formation which contains only a single fracture (two-wings). In some cases multiple formations may exist.

Comparative studies were made for two types of technology, base and advanced. (A detailed discussion of the difference between the two technologies is given in Chapter Seven). A description of the fracture lengths, conductivities, heights, and well spacing for the base and advanced cases is contained in Table 19. These data were used in determining production behavior and in calculating the economic parameters which are described in Chapter Four.

The base technology case deals with wells produced from a formation with a fracture having an effective length of 1,000 feet (from well bore to tip) and a conductivity of 500 millidarcy-feet (md-ft). For the advanced case, fracture conductivity was 1,000 md-ft and effective length was either 2,000 or 4,000 feet (from well bore to tip) depending on permeability level and whether the formation was lenticular or blanket-type. At higher permeability levels in blanket sands, the difference in production performance between a 2,000- and 4,000-foot fracture is insignificant. Thus, the cost of generating the additional length was not justified for the higher permeabilities in the blanket sands. However, in the lenticular sands, a 4,000-foot fracture was used at all permeability levels. This was done to contact as many remote lenses as possible and connect them to the well bore.

The fraction of the gas drained from these lenses was estimated by summing annual production from all of the individual lenses in a section. Linear flow production models were incorporated to calculate production from wells in lenticular formations.

The production simulator previously mentioned was used to calculate the performance of a formation over a range of specific sets of reservoir properties. These were tabulated as an aid in estimating permeability from well production history. However, the ultimate economic recovery from a well is controlled by a combination of individual well performance capabilities, gas prices, and costs. Cost data and economic details are discussed at length in Chapter Four and Appendix D, and will only be mentioned briefly here.

Cost data were collected from various companies and drilling costs from the Joint Association Survey were used.[2] Fracture estimating costs were obtained from service companies. These were

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[2]Joint Association Survey of the U.S. Oil and Gas Producing Industry, American Petroleum Institute and Mid-Continent Oil & Gas Association, Washington, D.C., 1977.

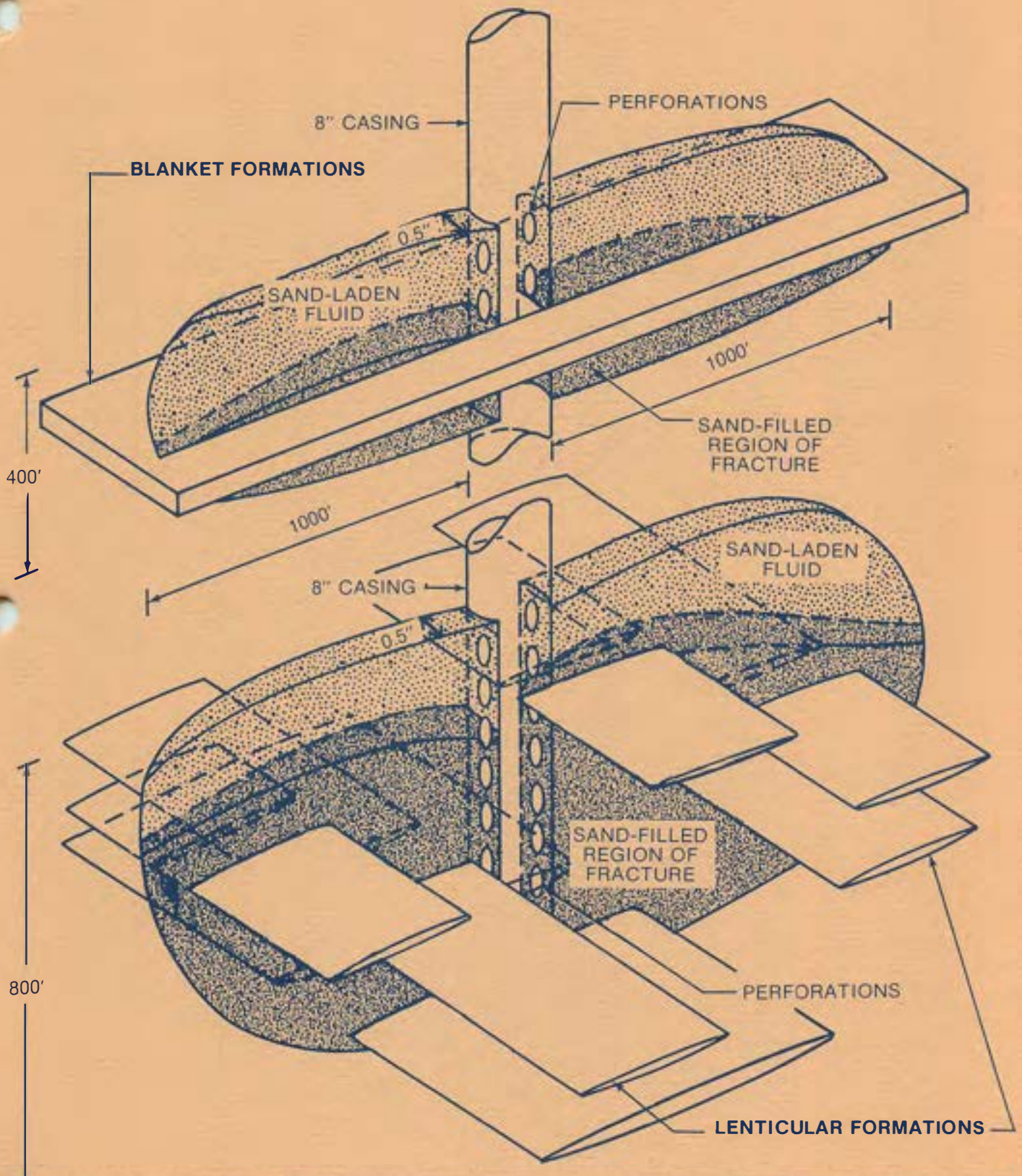


Figure 17. Conceptual Fractures Created by MHF for Blanket and Lenticular Formations.

TABLE 19

Base vs. Advanced Technology and Regulation

	Blanket Formations		Lenticular Formations	
	Base	Advanced	Base	Advanced
1. Fracture Height	4 x Net Pay	3 x Net Pay	6 x Net Pay	4 x Net Pay
Range (ft)	200 - 600	150 - 400	300 - 1,000	200 - 600
2. Fracture Conductivity* (Md-Ft)	500	1,000	500	1,000
3. Fracture Length, Well Bore to Tip (Ft), Permeability ≥ 0.1 md				
Effectively Achieved	1,000'	2,000'	1,000'	4,000'
Hydraulic Design Required	1,700'	2,500'	1,700'	5,000'
Permeability < 0.1 md				
Effectively Achieved	1,000'	4,000'	1,000'	4,000'
Hydraulic Design Required	1,700'	5,000'	1,700'	5,000'
4. Field Development				
Wells Per Section (Max.)	4	12	4	12
Acres Per Well (Min.)	160	53	160	53

*Product of fracture permeability and fracture width.

verified by comparison with actual costs from experience in each of the basins studied. All costs indicated are in January 1, 1979, dollars, and all calculations are made in constant dollars. Economics were calculated using the exploration and production full-cycle economic simulator model described in Chapter Four. This economic model handles the economics associated with the exploration, drilling, and production in a tight gas province.

After well performance was calculated, it was reviewed by the basin geologist/engineer team and compared with well production data from their files. If there was not a reasonable match, the input data were reexamined and revised. Field experience provided a confirming guide. If necessary, well performance was recalculated, and the process reiterated until agreement was reached. After this, the data were sent to the economists for evaluation. All cost data used were verified by the study participants as well as by several outside companies. The preliminary economic results were returned to the basin teams for verification with their experience. If these data were suspect, all geology and well performance data were reexamined and adjusted until the basin team was in agreement.

Example Resource Estimate -- San Juan Basin

A sample resource estimate for the San Juan basin follows to illustrate the procedures used to develop the resource estimates for all 12 basins included in this study. The procedures can be summarized as follows:

- Estimate for each formation of interest the area within the basin that contains gas.
- Estimate the formation area that contains conventional gas, productive at 1979 prices and at the technology and regulations commonly practiced in 1979.
- Estimate the formation area that contains tight gas. (In many localities the tight area and the conventional area overlap.)
- Estimate the porosity and net pay using log data and test data from poor quality, uneconomical wells in the tight gas formation. Then estimate an average permeability in reservoirs from the tables to match well performance test data.
- Estimate a range of reservoir conditions after studying several key wells in the formation.
- Use a set of guideline tables to estimate well production history for various reservoir conditions expected to be found in tight gas areas.
- Compare actual performance of wells completed in the tight gas formation with the calculated performance in the tables.

In delineating areas for further drilling of the Dakota formation in the San Juan basin, the geologist outlined an area around and outside the present Dakota field limits. The outline was restricted to certain limits which were designated by the encountering of updip water and/or the silting out of the sands. In assigning parameters for the undeveloped tight sand areas, reservoir characteristics of a lower quality than those of the field proper were used, as these undeveloped areas, in general, exhibit poor producing characteristics. Gas-filled porosities ranged from 1.5 to 5 percent, in situ gas permeabilities ranged from 0.0004 to 0.04 md, and net thicknesses ranged from 10 to 30 feet. Average depth was 7,150 feet. A total of 1,188 sections of potential tight gas sands are estimated to exist around the Dakota formation.

After making estimates of the ranges of porosity, permeability, and net pay thickness, the geologist estimates the areal extent of these reservoir characteristics. A plot similar to the one shown in Figure 18 is most helpful. In this case, based on his knowledge and judgment, the geologist has indicated that there is no appreciable area in the productive part of the basin with permeability as high as 0.1 md. The highest average permeability to be considered is 0.04 md, with about 6.3 percent of the basin having this value. The minimum average permeability is 0.0004 md. Cumulative area to this point is 100 percent. Points between these extremes are plotted at 0.01, 0.004, and 0.001 md. This plot determines values shown on Table 20.

There is no rigorous relationship between permeability and porosity, but for the purposes of estimation, probable values were made by a semi-logarithmic plot, as shown in Figure 19. Here discrete values of average porosity are plotted against the average permeability. A line through these points permits porosity/permeability values to be read for intermediate values.

A similar method is used to develop a plot of permeability vs. net pay thickness, as shown in Figure 20. The assumption for this particular example is that when a well hits a high average permeability zone, the net pay tends to be small. The low average permeability zones tend to be thicker.

The value of the plots can be seen in the data sheet in Table 20. These data are used as input to a production model which predicts well performance. Permeability, porosity, and net pay thickness, along with formation pressure and temperature, determine the production rate and ultimate recovery per well for each set of values selected from the plots. Without these values no quantitative estimates of gas production vs. selling price can be made. Details of the gas potential distribution are shown in Table 21.

The Dakota formation of the San Juan basin is different from the producing areas of other basins in that some degree of production can be expected at almost any location within the limits as defined by updip water and the silting out of the sands; i.e., localized structural traps are nonexistent and production deviations

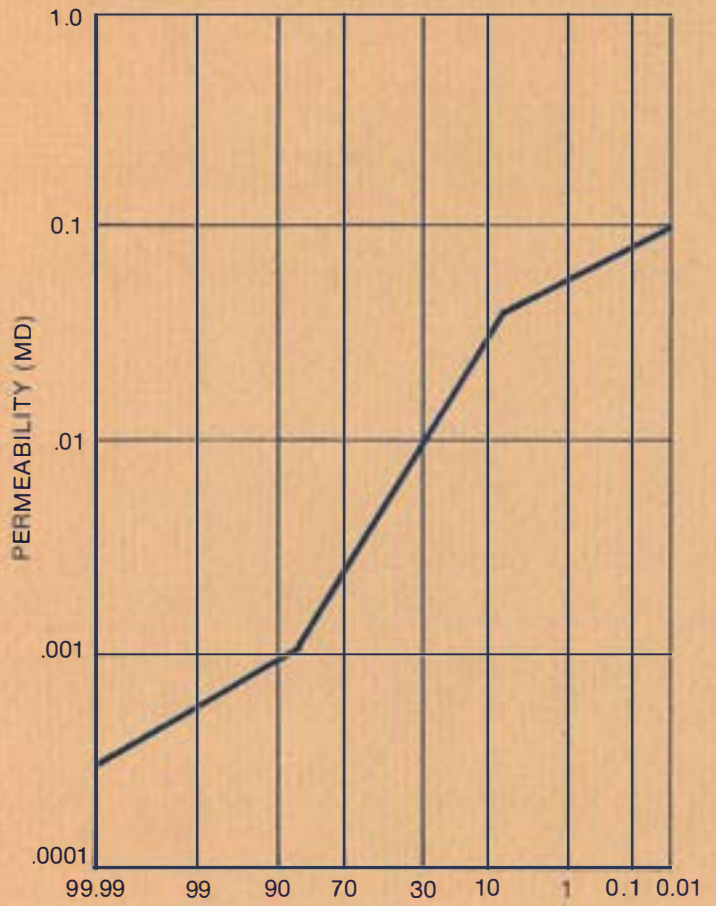


Figure 18. Distribution of In Situ Gas Permeability Across the Basin.

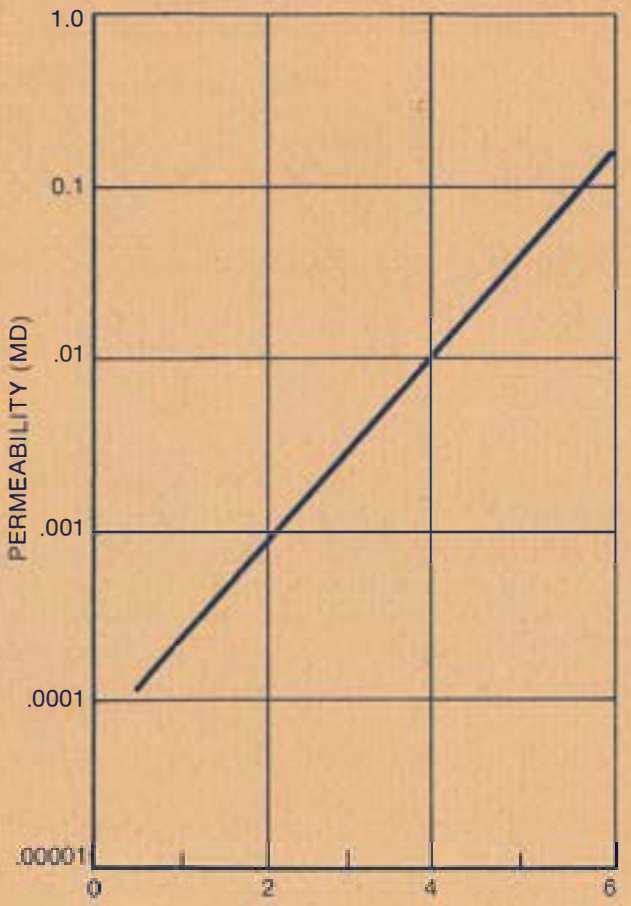


Figure 19. Gas Porosity vs. In Situ Effective Gas Permeability.

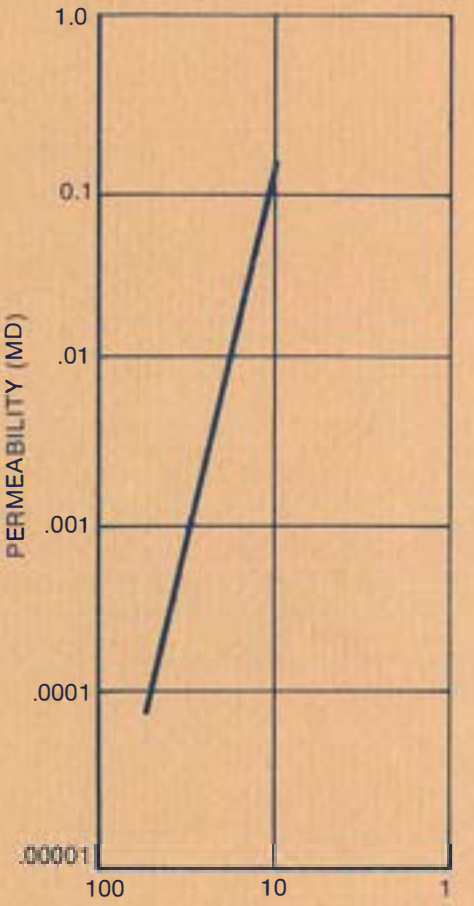


Figure 20. Net Pay vs. In Situ Effective Gas Permeability.

TABLE 20

Geological Data Summary

Total Basin Area (Sections): 8,000
Type: Blanket

Basin: San Juan
Subbasin:
Formation: Dakota

Depth (Ft.): 7150
Pressure (PSIA): 3090
Temperature (°F): 222

NGL(BBL/MMCF): 5.

Average Perm. (MD)	Productive Area (Sections)	H/C Gas Porosity (%)	Net Pay Thickness (Ft.)	Estimated Gas in Place at Reservoir Cond. (BCF)	Max. Recoverable Gas (BCF)	For Each Drilling Location W/C: Probability That State of Nature is Productive	Probability that W/C is Productive, Given that State of Nature is Prod 1st W/C	2nd W/C
0.04	75	5.0	10	184.13	142	0.93	0.95	1.0
0.01	150	4.0	15	441.9	321	0.93	0.95	1.0
0.004	515	3.0	20	1,517.19	1,031	0.93	0.95	1.0
0.001	300	2.25	25	828.0	526	0.85	0.95	1.0
0.0004	148	1.5	30	327.08	193	0.85	0.95	1.0
	1,188			3,298	2,213			

TABLE 21

Recoverable Gas In Place Computation Sheet

BASIN SAN JUAN — BLANKET SAND — DATE 9/28/79

TRAP NO.	DESCRIPTION	AVER. PERM. (MD)	NET PAY (FT.)	H/C GAS POROSITY (FRACTION)	GAS-IN-PLACE RESR. COND. (BCF/SECTION)	TECH.REC. GIP (BCF/SECT.)	MAX. RECOV. FACTOR	MAX REC. GIP (BCF/SECT.)	NO. OF SECTIONS	ULT.REC. GIP (BCF)
1		.04	10	.05	2.455	2.23	.85	1.89	75	142
2		.01	15	.04	2.946	2.67	.80	2.14	150	321
3		.004	20	.03	2.946	2.67	.75	2.00	515	1031
4		.001	25	.0225	2.76	2.50	.70	1.75	300	526
5		.0004	30	.015	2.21	2.00	.65	1.3	148	193
									1188	2213

INITIAL RESERVOIR PRESSURE P_i = 3090 PSI

RESERVOIR TEMPERATURE T = 222 °F

GAS COMP.FACTOR,RESERVOIR, Z_i = 0.91

GAS COMP.FACTOR, WELLHEAD, Z_w = 0.977

are the result of changing reservoir characteristics and/or the localized area of natural fractures.

The exploration simulator was programmed to take these basin characteristics into account. Figure 21 shows the field size distribution of producible gas for the Dakota formation. The state of nature assigned to each permeability level is given in Table 20. For this case, 93 percent of the prospects are estimated to be productive for the first three permeability levels and 85 percent for the last two levels. The first wildcat drilled in a potentially productive area is successful 95 percent of the time; the second, if needed, is always successful. However, a successful wildcat must meet economic criteria before going on stream and initiating field development. Table 22 shows the degree to which recoverable gas depends upon reservoir characteristics, gas selling price, and discounted cash flow rate of return. These tables also show increasing wildcat success as price increases. Table 22 shows these data for the base technology case. Table 23 covers advanced technology.

The number of wells per section used in the model depends upon the maximum recoverable gas in place (from Table 21) and upon ultimate recovery per well. Table 24 lists the base case ultimate recovery per well by permeability level as supplied by the well production model. Table 25 shows the same data for advanced technology. For base case total recovery calculations, the constraint of no more than four wells per section for the base case, Table 26, limits fractional recovery to 0.603 for the 0.001 md level and to 0.48 for the 0.0004 md level. In the advanced case, Table 25, the constraint of 12 wells per section does not limit ultimate recovery from a section of land. In fact, here it can all be produced with fewer than the maximum 12 wells per section.

The foregoing procedures applied to the San Juan basin illustrate the development of the estimate of the recoverable tight gas resource contained in the blanket Dakota formation in the basin.

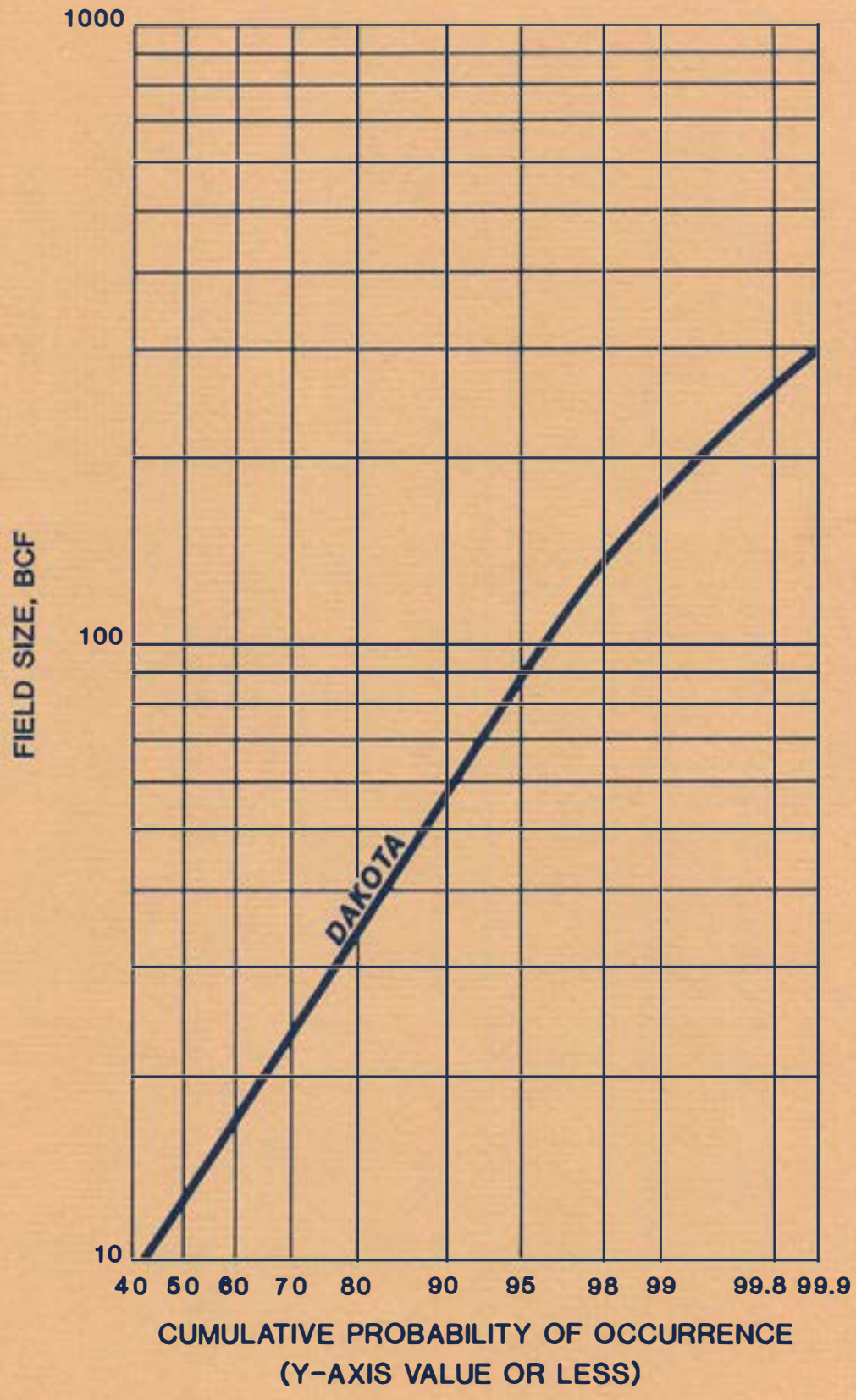


Figure 21. Field Size Distribution Curve—San Juan.

TABLE 22

ECONOMICS SUMMARY

BASIN San Juan
SUB BASIN
FORMATION Dakota
TECHNOLOGY Base
DATE May 1980

CASE NO.	GAS PRICE $/MCF	PROFIT. PROSP. I	K-LEVELS ON STREAM NO. VALUE *	AVERAGE PER PROSPECT: E & P INVEST. $M	GAS PROD. BCF	NET PRES. VALUE $M	DCF RATE OF RETURN %	BASIN TOTALS: GAS RECOVER. AT PRICE, BCF	MAX RECOV. GIP, BCF	MAX NO. PROSP. AT PRICE	WILDCAT SUCCESS %	WELLS: WILDCAT DRY	WILDCAT PROD.	DEVELOPMENT DRY	DEVELOPMENT PROD.	TOTAL
Discount Rate 10%																
16011 11	1.50	6.2	1 C	1357	1.889	-292	3.7	-	-	-	5.3	-	-	-	-	-
21	2.50	17.6	2 CD	3420	5.527	392	13.8	463	463	84	15.1	83	15	120	480	697
31	3.10	56.2	3 CDE	12477	16.165	1690	15.8	1494	1494	92	48.3	55	52	569	2277	2953
41	3.50	"	" "	"	"	2602	19.1	"	"	"	"	"	"	"	"	"
51	5.00	"	" "	"	"	6040	32.7	"	"	"	"	"	"	"	"	"
61	7.00	76.9	4 CDEF	19475	21.227	11711	40.8	1812	2020	85	66.1	33	65	839	3355	4293
71	9.00	"	" "	"	"	17468	59.9	"	"	"	"	"	"	"	"	"
81	12.00	88.7	5 CDEFG	24132	23.224	26920	77.1	1905	2213	82	76.3	23	73	1010	4040	5145
Discount Rate 15%																
12	1.50	0	0 -	702	-	-428	0	-	-	-	0	-	-	-	-	-
22	2.50	6.2	1 C	1357	1.889	-200	9.6	-	-	-	5.3	-	-	-	-	-
32	3.10	17.6	2 CD	3420	5.527	259	18.5	463	463	84	15.1	83	15	120	480	697
42	3.50	"	" "	"	"	488	21.7	"	"	"	"	"	"	"	"	"
52	5.00	56.2	3 CDE	12477	16.165	3202	32.7	1494	1494	92	48.3	55	52	569	2277	2953
62	7.00	"	" "	"	"	6400	53.0	"	"	"	"	"	"	"	"	"
72	9.00	76.9	4 CDEF	19475	21.227	10639	59.9	1812	2020	85	66.1	33	65	839	3355	4293
82	12.00	"	" "	"	"	16670	91.4	"	"	"	"	"	"	"	"	"
Discount Rate 20%																
13	1.50	0	0 -	702	-	-437	0	-	-	-	0	-	-	-	-	-
23	2.50	6.2	1 C	1357	1.889	-304	9.6	-	-	-	5.3	-	-	-	-	-
33	3.10	"	" "	"	"	-217	12.8	-	-	-	"	-	-	-	-	-
43	3.50	17.6	2 CD	3420	5.527	96	21.7	463	463	84	15.1	83	15	120	480	697
53	5.00	56.2	3 CDE	12477	16.165	1680	32.7	1494	1494	92	48.3	55	52	569	2277	2953
63	7.00	"	" "	"	"	4079	53.0	"	"	"	"	"	"	"	"	"
73	9.00	"	" "	"	"	6479	74.5	"	"	"	"	"	"	"	"	"
83	12.00	76.9	4 CDEF	19475	21.227	11431	91.4	1812	2020	85	66.1	33	65	839	3355	4293

* CODE:

C	D	E	F	G
0.04	0.01	0.004	0.001	0.0004

TABLE 23

ECONOMICS SUMMARY

BASIN San Juan

SUB BASIN

FORMATION Dakota

TECHNOLOGY Advanced

DATE May 1980

CASE NO.	GAS PRICE $/MCF	PROFIT. PROSP. %	K-LEVELS ON STREAM NO.	K-LEVELS ON STREAM VALUE *	AVERAGE PER PROSPECT: E & P INVEST. $M	AVERAGE PER PROSPECT: GAS PROD. BCF	AVERAGE PER PROSPECT: NET PRES. VALUE $M	AVERAGE PER PROSPECT: DCF RATE OF RETURN %	BASIN TOTALS: GAS RECOVER. AT PRICE BCF	BASIN TOTALS: MAX RECOV. GIP BCF	BASIN TOTALS: MAX NO. PROSP. AT PRICE	WELLS: WILDCAT SUCCESS %	WELLS: WILDCAT DRY	WELLS: WILDCAT PROD.	WELLS: DEVELOPMENT DRY	WELLS: DEVELOPMENT PROD.	WELLS: TOTAL
Discount Rate 10%																	
1601211	1.50	17.6	2	CD	2874	5.527	-182	7.9	-	-	-	15.1	-	-	-	-	-
21	2.50	56.2	3	CDE	7950	16.165	2360	23.1	1494	1494	92	48.3	55	52	189	757	1053
31	3.10	"	"	"	"	"	3802	31.7	"	"	"	"	"	"	"	"	"
41	3.50	76.4	4	CDEF	13979	22.621	5577	30.2	2020	2020	89	66.1	35	68	343	1372	1819
51	5.00	"	"	"	"	"	10682	52.3	"	"	"	"	"	"	"	"	"
61	7.00	88.7	5	CDEFG	18840	25.786	18864	72.3	2213	2213	86	76.3	24	76	456	1825	2381
71	9.00	"	"	"	"	"	26700	104.0	"	"	"	"	"	"	"	"	"
81	12.00	"	"	"	"	"	38455	150.8	"	"	"	"	"	"	"	"	"
Discount Rate 15%																	
12	1.50	6.2	1	C	1552	1.889	-508	2.3	-	-	-	5.3	-	-	-	-	-
22	2.50	56.2	3	CDE	7950	16.165	1018	23.1	1494	1494	92	48.3	55	52	189	757	1053
32	3.10	"	"	"	"	"	2039	31.7	"	"	"	"	"	"	"	"	"
42	3.50	"	"	"	"	"	2720	37.5	"	"	"	"	"	"	"	"	"
52	5.00	76.9	4	CDEF	13979	22.621	6529	52.3	2020	2020	89	66.1	35	68	343	1372	1819
62	7.00	88.7	5	CDEFG	18840	25.786	12037	72.3	2213	2213	86	76.3	24	76	456	1825	2381
72	9.00	"	"	"	"	"	17625	104.0	"	"	"	"	"	"	"	"	"
82	12.00	"	"	"	"	"	26007	150.8	"	"	"	"	"	"	"	"	"
Discount Rate 20%																	
13	1.50	0	0	-	1039	-	-620	0	-	-	-	0	-	-	-	-	-
23	2.50	17.6	2	CD	2874	5.527	-128	17.4	-	-	-	15.1	-	-	-	-	-
33	3.10	56.2	3	CDE	7950	16.165	1068	31.7	1494	1494	92	48.3	55	52	189	757	1053
43	3.50	"	"	"	"	"	1582	37.5	"	"	"	"	"	"	"	"	"
53	5.00	"	"	"	"	"	3517	59.7	"	"	"	"	"	"	"	"	"
63	7.00	76.9	4	CDEF	13979	22.621	7874	84.0	2020	2020	89	66.1	35	68	343	1372	1819
73	9.00	88.7	5	CDEFG	18840	25.786	12416	104.0	2213	2213	86	76.3	24	76	456	1825	2381
83	12.00	"	"	"	"	"	18799	150.8	"	"	"	"	"	"	"	"	"

* CODE:

C	D	E	F	G
0.04	0.01	0.004	0.001	0.0004

TABLE 24

WELL PRODUCTION SUMMARY--BASE CASE

SAN JUAN, DAKOTA

GAS PRODUCTION (MMCF/YEAR/WELL)

YEAR	K = 0.4	0.1	0.04	0.01	0.004	0.001	0.0004	0.0001	0.00004	0.00001 (MD)
1			131	86	62	32	20			
2			84	53	35	17	10			
5			59	34	23	10	6			
10			46	26	17	8	5			
15			38	23	15	7	4			
20			31	21	14	6	3			
30			23	18	12	5	3			
30-YEAR CUMM. PROD. (MMCF)			1323	827	556	263	155			

TABLE 25

WELL PRODUCTION SUMMARY--ADVANCED CASE

SAN JUAN, DAKOTA

GAS PRODUCTION (MMCF/YEAR/WELL)

YEAR	K = 0.4	0.1	0.04	0.01	0.004	0.001	0.0004	0.0001	0.00004	0.00001 (MD)
1			289	235	202	117	76			
2			200	148	118	65	40			
5			136	97	74	38	23			
10			99	71	53	28	17			
15			81	59	44	22	14			
20			66	51	39	19	12			
30			49	42	32	16	10			
30-YEAR CUMM. PROD. (MMCF)			2881	2171	1670	885	545			

TABLE 26

PRODUCTION WELL REQUIREMENTS

BASIN: San Juan
SUB-BASIN:
FORMATION: Dakota

PERM. (MD)	BASE CASE: NUMBER OF WELLS/SECTION REQD. TO PRODUCE ALL GAS	BASE CASE: NUMBER OF WELLS/SECTION ACTUALLY USED (MAX=4)	BASE CASE: RECOVERABLE GAS FROM ACTUAL WELLS (BCF)	ADVANCED CASE: NUMBER OF WELLS/SECTION REQD. TO PRODUCE ALL GAS	ADVANCED CASE: NUMBER OF WELLS/SECTION ACTUALLY USED (MAX=12)	ADVANCED CASE: RECOVERABLE GAS FROM ACTUAL WELLS (BCF)
.04	1.4	1.4	142	.66	.66	142
.01	2.6	2.6	321	1.1	1.1	321
.004	3.6	3.6	1031	1.2	1.2	1031
.001	6.6 *	4.	318	1.97	1.97	526
.0004	8.3	4.	93	2.38	2.38	193
			1905			2213

* Example calculation for 0.001 md permeability
Max recoverable gas in place = 526 BCF (Tables 20 and 21)
Number of sections with permeability of 0.001 md = 300 (Table 20)
BCF/Section = 526/300 = 1.75
Gas Production = 263 MMCF/year/well (Table 24)
Number of wells required to produce all gas = $\frac{1.75 \times 1000}{263}$ = 6.6 wells/section

Actual wells used = 4
Recoverable gas from actual wells = 4 x 300 x 263/1000 = 318 BCF
Rounding in these tables and in the computer does not always allow a exact match of numerical values.
Well development factor or well drainage efficiency = $\frac{4}{6.6}$ = 0.606 or 60.6 percent.

Chapter Four

ECONOMIC APPRAISAL AND CALCULATION METHODS FOR TIGHT GAS EXPLORATION AND DEVELOPMENT

ECONOMIC EVALUATION PARAMETERS

Economic evaluation of the tight gas reservoirs was accomplished by means of exploration and production simulation in a computer model. Input to the model was based on judgments and projections of professional geologists and engineers familiar with the geological basins being evaluated. The economic evaluation parameters used for the tight gas reservoirs study included the following:

- Basis
  - January 1, 1979, dollars held constant.
- Desired Output
  - Additions to ultimate recovery, by year, to the year 2000 as a function of gas price and state of technology.
  - Production rates, by year, to the year 2000.
- Gas Price
  - Price at point of sale. All capital to that point, such as compression and gathering lines, should be included in the evaluation. Final calculations were made for $1.50, $2.50, $3.10, $3.50, $5.00, $7.00, $9.00, and $12.00/MCF.
- Cases
  - Current technology -- likely to evolve and improve during normal operations; this is the base case.
  - Improved technology -- effect and timing to be determined for each gas source based on analysis of problems and improvements likely with large industry/government research, development, and testing programs.
- Other Parameters
  - Royalty -- one-eighth.
  - Taxes -- 46 percent federal income tax rate.
    2 percent state income tax rate.
    8 percent (of producer revenue) production, severance, and property tax.
    10 percent federal investment tax credit on tangible equipment.

- Depletion Allowance -- unit of production depletion allowance used to recover leasehold costs.

- Overhead -- 10 percent of invested capital.
  20 percent of direct operating expense.

- Treatment of costs for tax purposes.

  Expense intangible drilling and development costs.

  Capitalize tangible equipment and write-off by most favorable treatment under current tax laws and regulations.

- Treatment of dry hole costs and other risks. Dry hole costs, unsuccessful exploration, leasehold, and other non-recoverable costs were charged against successful wells.

- Rates of return include the losses from unsuccessful wells.

  Computed ultimate recovery for 10, 15, and 20 percent DCF ROR after tax.

These parameters were programmed into the model and form the basis for the economic evaluations. Lease cost was figured at $0.01/MCF for each field developed. Midyear discount factors were used. Investment and operating expenses varied with each location. The values used for each formation appear in the basin chapters of Part II of this report as "Investment and Operating Expenses." The methods used in estimating costs and expenses are explained in the following paragraphs.

Constant Dollar vs. Current Dollar

Adjustment for inflation has become an important factor in economic calculations. In order for the economic results of this study to have meaning, the relationship between constant dollars and current dollars must be explained.

All of the economics, prices, costs, expenses, taxes, and their interrelationships are expressed in terms of prices as of January 1, 1979. Some readers may use these results for comparison with the past, but most will compare them with the future. Most of the cost elements are related to drilling and equipping wells. The Independent Petroleum Association of America (IPAA) makes an annual survey of these costs and publishes an average cost index for the year, based on 1974 = 100.

The future inflation rates are unknown but have been estimated for this example to average about 16.4 percent per year to 1985. An operator considering a tight gas prospect may wish to correct the price offered for tight gas in current dollars back to January 1, 1979, dollars. The following schedule may help in making the connection so that the economics in the report can be compared with his own estimates.

For example, for the Piceance basin, Fort Union formation, drilling, fracturing, and equipping the wells contributes over 98 percent of the total cost, as shown in Table 42, which appears later in this chapter. The IPAA index should apply. If a price of $5.97/MCF were offered for July 1, 1982, the January 1, 1979, dollar equivalent would be about $3.33/MCF.

At a $3.50 price, Table 40 indicates a real rate of return of 22.4 percent, and a rate of 18.4 percent at a $3.10 price. The economic performance at $3.30/MCF can be estimated as the average of performance at $3.10 and $3.50/MCF. A play involving several prospects would be expected to result in about 31 percent of them being profitable. The expected investment per prospect of $2,871,000 would have increased to about $5,183,000 by 1982, but a 20.4 percent rate of return would still be expected. More gas could be produced from the prospects at a higher price or with longer fractures, as shown in Table 41.

COST ESTIMATES

Cost estimates are provided for drilling, fracturing, operating, surface equipment and gathering lines, and compressor fuel.

Drilling Costs

Data for the basins of interest were selected from the 1977 Joint Association Survey of Drilling and Completion Costs. Treatment of these data is described in Appendix D. Table 27, based on an analysis of these costs, was used to compute drilling costs for this report. For example, the Piceance Creek-Fort Union drilling cost was computed as follows (see the basin chapters of Part II of this report):

From the table: Slope = 0.0002335
Intercept = 11.252823

From geological data: Depth = 5,000 ft.

Cost in 1977 dollars = $e^{11.252823 + 5{,}000 \times 0.0002335}$ = $247,787

Cost in 1979 dollars = 1.187* x $247,787 = $294,123

For tax purposes, assume: Intangible = 0.7 x cost = $205,886
Tangible = 0.3 x cost = $ 88,237

*Recent data in Table 28 indicate that well cost estimates made for this study in early 1978 were 2 percent low.

TABLE 27

Drilling and Completion Cost Equation Coefficients -- 1977

Region	Basin	Depth Range	Slope	Intercept	R^2	Error
1. Colorado	Denver	1250-9999	.0002139	11.089932	.85449	1.1876
2. E. New Mexico	Raton	0-19999	.0002206	10.830232	.96221	1.1843
3. Montana	Northern Basin	0-3749	.0004148	10.048623	.85165	1.0874
	Williston					
4. Oklahoma-Arkansas	Arkoma-Ouachita	3750-9999	.0002203	10.867174	.95886	1.0944
5. Oklahoma-Texas 10	Anadarko	0-19999	.0002610	10.455285	.96561	1.2261
6. Wyoming-Utah	Big Horn	2500-4999	.0002691	11.011735	.96771	1.0340
	Wind River					
	Piceance	5000-14999	.0002335	11.252823	.95568	1.1200
	Greater Green River					
	Uintah					
	Wasatch					
	Snake River					
	Douglas Creek					
7. Texas 6-N. Louisiana	Cotton Valley	7500-12499	.0003038	10.393858	.99701	1.0138
8. Texas 7	Sonora	5000-9999	.0001914	10.831515	.99998	1.0007
9. Texas 9	Fort Worth	0-12499	.0004919	8.938533	.98306	1.0858
10. Texas 2,3,4	Edwards Lime	0-17499	.0002903	10.4716585	.95015	1.2382
11. W. New Mexico	San Juan	5000-9999	.0001999	11.060594	.99988	1.0012

Cost (1977 $) = $e^{[\text{Intercept} + \text{Slope (depth in ft.)}]}$

Adjust costs about 12% per year (1-1/2 years) to bring to 1/1/79.

Results based on 1977 JAS data - depths selected for basins.

TABLE 28

Relationship of Constant-Dollar Prices and Costs
To Past and Estimated Future Current-Dollar Prices and Costs

Mid-Year	Price Index for Drilling and Equipping Wells (IPAA Index)	Percentage Change In Index From Previous Year	Current Prices for Tight Gas in Various Years Adjusted for Index January 1, 1979, Price per MCF				
			$2.50	$3.33	$3.50	$5.00	$9.00
1973	81.1		$1.15	$1.53	$1.61	$2.30	$4.15
1974	100.0	23.3	1.42	1.89	1.99	2.84	5.11
1975	117.7	17.7	1.67	2.23	2.34	3.34	6.02
1976	128.8	9.4	1.83	2.44	2.56	3.66	6.59
1977	145.2	12.7	2.06	2.75	2.89	4.13	7.42
1978	162.7	12.1	2.31	3.08	3.24	4.62	8.32
January 1, 1979	176.0	Report Constant $, Price:	2.50	3.33	3.50	5.00	9.00
1979	190.0	16.8	2.70	3.59	3.78	5.40	9.72
1980	232.8†	22.5†	3.31	4.40	4.63	6.61	11.90
September 22, 1980	242.3†	16.4*	3.44	4.59	4.82	6.89	12.40
1981	271.0†	16.4†	3.85	5.13	5.39	7.70	13.86
1982	315.4†	16.4†	4.48	5.97	6.27	8.96	16.13
1983	367.1†	16.4†	5.21	6.95	7.30	10.43	18.77
1984	427.4†	16.4†	6.07	8.09	8.50	12.14	21.85
1985	497.4†	16.4†	7.07	9.41	9.89	14.13	25.45

*Average.
†Estimated.

Estimation of Fracture Treatment Cost

The methods used in estimating fracture costs are set forth in Appendix D. These are based on costs furnished by three service companies for frac fluid volumes ranging from 100,000 to 1,200,000 gallons at depths of from 4,000 to 12,000 feet. Essentially, the basic cost of the treatment is the cost at 4,000 feet in the least expensive area, such as eastern Texas. These costs are adjusted for greater depths and more expensive locations by appropriate depth and location factors (see Tables 29 and 30 for adjustment factors). In addition, at depths of 15,000 feet or more, bauxite replaces sand as the proppant, with added cost.

TABLE 29

Adjustment Factors for Frac Treatment Costs
Adjustment Factor for Well Location

Basin	$AF_{Location}$
Sonora, Cotton Valley, and Ouachita	1.15
Denver	1.17
Green River, Wind River, Big Horn, Northern Great Plains, Williston	1.25
San Juan, Uinta, Douglas Creek, Piceance	1.28

TABLE 30

Adjustment Factors for Frac Treatment Costs
Adjustment Factor for Depth

Depth	AF_{Depth}
4,000 Feet	1.000
6,000 Feet	1.063
8,000 Feet	1.180
10,000 Feet	1.296
12,000 Feet	1.310
15,000 Feet	1.400

Continuing the Fort Union example, it is seen that the net pay thickness for the first permeability level is 12 feet (see Table 31). The sand is lenticular. It is assumed that the created fracture height will be six times net thickness, or 72 feet; however, for cost estimating, a minimum of a 300-foot fracture height is assumed. (Thus, all net pay of 50 feet or less costs the same amount.)

From Figure 22 is taken a frac volume of 295,000 gallons for a 1,000-foot fracture with a height of 300 feet. From Figure 23 is taken $108,000. Adjustment for location and depth brings the total cost to $142,110.

Operating Costs

The operating costs included in Table 32 have been collected from producing companies that are operating in the various basins. These numbers are the average 1978 cost for each area and are updated to 1979 costs using a 12.5 percent cost multiplier. The operating and maintenance costs include normal operating expenses, surface and subsurface repairs, maintenance, and services. These figures also include field or district expense and ad valorem taxes but do not include corporate administrative and overhead costs.

Surface Equipment and Gathering Line Costs

The one-time cost for surface equipment assumes that the gas purchaser will pick up the gas close to the wellhead. The equipment would include such items as separator, dehydrator, meter run and meter house, miscellaneous valves, fittings, concrete pads, tankage, and installation charges. Higher cost in the Northern Great Plains results from in-field compressors for these low pressure wells. Gathering line costs are assumed to be paid for by the purchaser.

Gathering line costs not included in the gas sales price ranged from $15,000 to $50,000 per well, depending on line size. One example of a mainline cost per well totaled $137,035. Two thousand wells were involved. Costs to transport mainline gas varied from $0.50/MCF for a line 30 inches in diameter and 500 miles in length to $0.75-$1.00/MCF for a line 42 inches in diameter and 1,500 miles in length. Costs of this magnitude can be paid by the purchaser without becoming a constraint to gas production.

Fuel for compressors is supplied by the lease. The amount required varies by basin, but its maximum value is approximately 3 percent of the gas produced. The schedule used called for no compression during the first eight years, 51.6 percent of maximum value for the ninth through 19th years, and maximum value for the remainder of the project life. The exception to this schedule is the Northern Great Plains, where 5.18 percent of the production is used for compressor fuel for all years of the project. These costs are tabulated in the basin evaluations of Part II of this report.

TABLE 31

Geological Data Summary

Total Basin Area (Sections): 7100
Type: Lenticular

Basin: Piceance
Subbasin: -
Formation: Ft. Union

Depth (Ft.): 5000
Pressure (PSIA): 2100
Temperature (°F): 135

NGL(BBL/MMCF): 20.

Average Perm. (MD)	Productive Area (Sections)	H/C Gas Porosity (%)	Net Pay Thickness (Ft.)	Estimated Gas in Place at Reservoir Cond. (BCF)	Max. Recoverable Gas (BCF)	For Each Drilling Location W/C: Probability That State of Nature is Productive	Probability that W/C is Productive, Given that State of Nature is Prod. 1st W/C	2nd W/C
0.1	4	7	12	14	11	0.20	1.0	-
0.03	25	6	22	140	107	0.40	1.0	-
0.01	78	5.1	34	573	423	0.45	1.0	-
0.003	131	4.4	48	1,172	805	0.55	1.0	-
0.001	81	3.8	62	809	521	0.65	1.0	-
0.0003	35	3.2	80	380	230	0.75	1.0	-
	354			3,088	2,097			

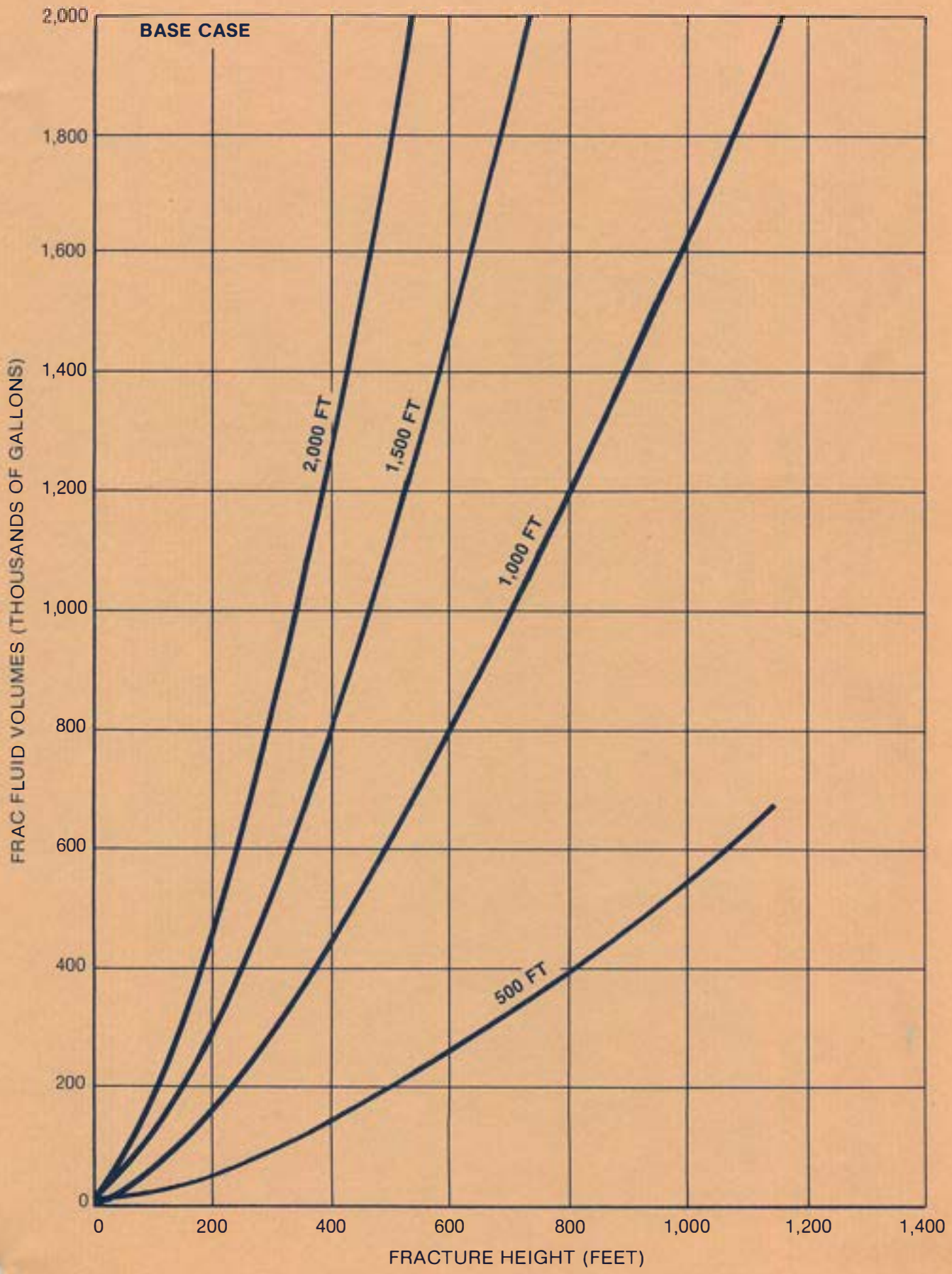


Figure 22. Frac Fluid Volume to Create Fractures of Various Propped Lengths ($L_{prop} = 0.6\ L_{hyd}$).

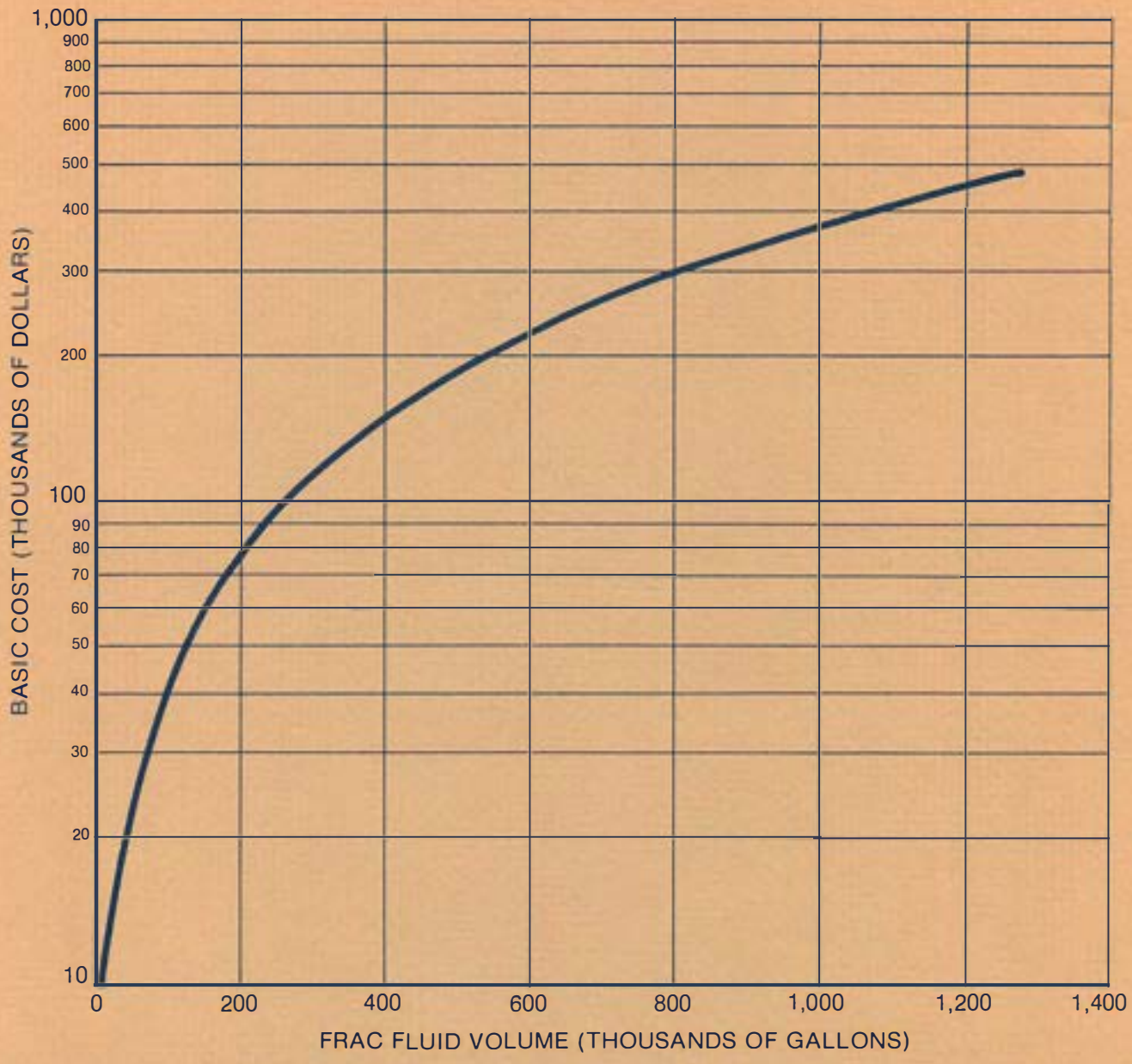


Figure 23. Basic Cost of Fracturing Treatment as a Function of Fluid Volume.

TABLE 32

Surface Equipment and Operating Costs

Basin	Surface Equipment ($/Well)	Operating Cost ($/Well/Year)
Cotton Valley	45,000	14,400
Edwards Lime	45,000	7,500
Northern Great Plains	103,000	7,200
Rocky Mountains	45,000	10,000
San Juan	45,000	6,750
Val Verde	45,000	7,500

EXPLORATION AND PRODUCTION SIMULATOR FOR TIGHT GAS RESERVOIRS

General Description of the Simulator

The Tight Gas Exploration and Production Simulator (E and P Simulator) is a set of computer programs designed to model exploration of natural gas resources in tight reservoirs. The model utilizes a cash flow stream to compute standard profitability indicators, including discounted present worth, discounted cash flow rate of return, payout time, profit per investment, maximum unrecovered investment, net cash recovery after taxes, exploration expenditure, production investment, and operating expenses. Additions to reserves (ultimate recovery) and annual production rates are tabulated.

The E and P Simulator comprises two main sections. The first section is a basin evaluation using the Monte Carlo technique, whereby input to the computations is obtained by sampling probability distributions from much of the geological data, and by various schedules and tables for production and cost data. The proper timing of events such as the drilling of wildcats and development wells, as well as expenditures and revenues, is provided in this section. A profit and loss statement with U.S. tax computations is the basis for determining profitability criteria. It is assumed that the productive area of a geological basin is being evaluated and that a large number of prospects are available in the area. Many prospects will be dry, while others will be productive, with field sizes determined from the geological input data. From these data an average field size and production schedule will be available for use in the second section of the E and P Simulator. Such models employing the Monte Carlo sampling of probability distribution have been in use in the oil industry for about 15 years.[1]

The second section of the E and P Simulator is a computer program that provides for scheduling investments in the geological basins over a number of years. This section makes a summation of the results of the basin analyses just described, including production, cash flow, and profitability. Constraints to the scheduling model include the following:

- The number of prospects in a basin must not exceed the number required to produce all the recoverable gas in place.
- Annual investment should not exceed the industry's ability to supply investment capital.
- Production should not exceed pipeline capacity.
- Rigs must be available to drill the scheduled wildcats and development wells.

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[1]Newendorp, Paul D., "Decision Analysis for Petroleum Exploration," pp. 369-490, The Petroleum Publishing Co., Tulsa, Oklahoma, 1975.

Special Feature of the Tight Gas Simulator

Study participants were asked to forecast additions to ultimate recovery and production rates by year to the year 2000 as a function of gas price and state of technology. The study group was asked to compute these values for 10, 15, and 20 percent discounted cash flow rates of return and for prices of $2.50, $3.50, $5.00, $7.00, and $9.00/MCF.

The three rates of return and five prices posed no problem; the simplest financial models provide for sensitivity studies in which discount rate and price vary. But the base case and advanced case technologies for tight gas reservoirs had to be defined, and some way had to be devised to accurately determine the effect of price escalation on ultimate recovery and production rates.

Recommendations from the engineers participating in the study were that the base case technology conform to current practice in the industry for tight sand production, and that the advanced case be what might be expected to result from industry and government research projects. (This subject is discussed in Chapter Seven of this report.) Briefly stated, the base case was comprised of no more than four wells per section with 1,000-foot fractures. The advanced case comprised a maximum of 12 wells per section and 4,000-foot fractures. Naturally, the wells with 1,000-foot fractures had lower production rates and lower ultimate recoveries per well than did the wells with 4,000-foot fractures; however, the longer fractures cost much more to create, providing an interesting financial tradeoff.

A description of the geological data is necessary before describing the exploration model's sensitivity to price. The geologists selected from five to 10 permeability levels with ranges of porosity and pay thickness. These data were input to the production model, which predicted ultimate recovery and production rate per well for each permeability level. As a rule, productivity decreased with lower permeability. The geological data also provided for computation of recoverable gas in place per section for each permeability level.

Describing the manner in which the number of wells per section is computed is best done by numerical example. Assume that in the first permeability level there are 10 BCF per section, and that a base case well will produce 2 BCF over its 30-year life. Dividing 10 BCF by 2 BCF per well yields 5 wells per section, which are required to produce all the available gas in 30 years. But the base case is limited to four wells per section. Therefore, the model drills only four wells and produces 8 BCF per section in the base case.

The advanced case well might produce 3.33 BCF over its 30-year life; it would require only three wells per section to produce 10 BCF. This number would be drilled. Of course, gas fields may be several sections in area with the number of wells drilled proportionately larger.

Assume that the 2 BCF base case well is 10,000 feet deep with attendant high drilling cost. The first gas price to be tested is $2.50. Assume further that a wildcat is drilled in the productive area containing 10 BCF per section. A profit and loss computation is made and shows a rate of return of 17 percent, meaning that this permeability level will be profitable at both a 10 and 15 percent DCF ROR, but not at 20 percent. The advanced case well producing 3.33 BCF might return 25 percent and be profitable at a 10, 15, and 20 percent ROR. However, as permeability decreases in the basin, the wells produce less. It is likely that a base case well of only 1.5 BCF of ultimate production in a lower permeability zone would be unprofitable at $2.50 but profitable at $3.50.

One more observation needs to be made. One or two permeability zones may be profitable at a given price. But these zones cannot be selectively drilled to the exclusion of all others because their locations are not known. The assumption is that the entire area will be drilled at each price level. Therefore, even though one or two permeability levels are profitable at a low price, it does not follow that the project will be profitable. The remaining permeability levels will be "dry" at the low price. At higher prices these dry areas become profitable producers.

The amount of gas producible at each price is tabulated in the economic summary tables for each formation. Each price represents an independent evaluation of the area.

Summary of Basin Evaluation

Figure 24 shows the flow of computations in the basin evaluation section of the E and P Simulator. Geological information from the basin to be analyzed is sampled to provide input for prospects to be drilled. A prospect is a wildcat location. If the wildcat is productive and profitable, development wells will be drilled. If it is dry, the wildcat will be adandoned and a new prospect selected.

A unique feature of this model is the treatment of the productive wildcat. Ultimate production and annual production rates are provided for wells drilled in each permeability zone. A complete cash flow analysis is made for each wildcat at the selected gas selling price and discount rate. If the wildcat shows a negative net present value, it is abandoned. An unprofitable wildcat is a dry hole with no return on investment. At a higher gas price the same wildcat may be profitable, thereby triggering field development.

However, the basin is evaluated at a single price and discount rate until all prospects are drilled. This simply means that a large number of prospects are drilled and averages per prospect are computed, including E and P investment, gas production, net present value, and DCF ROR.

The process begins again with a new (higher) gas price. The same prospects are drilled, but the higher price may make some

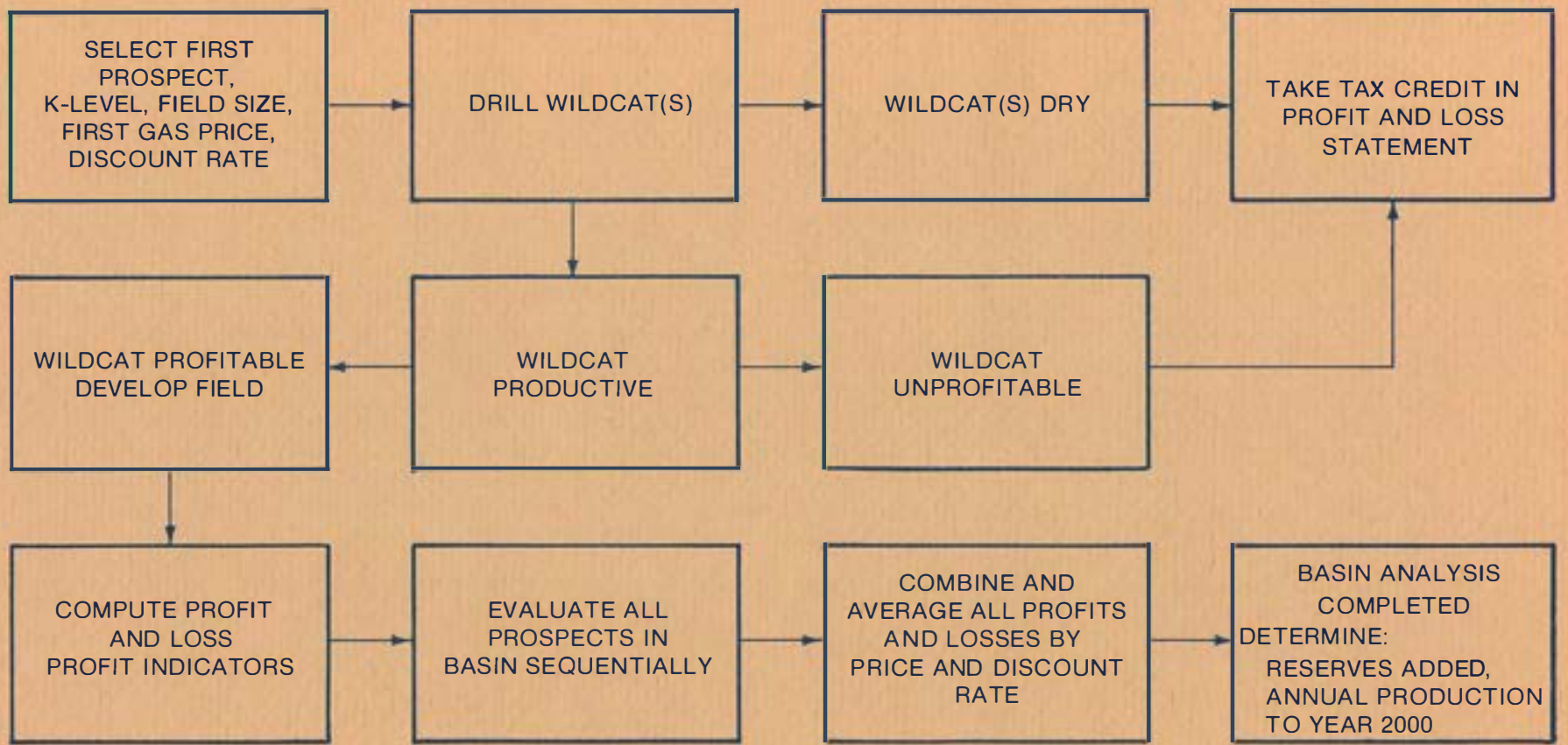


Figure 24. Tight Gas Exploration and Production Simulator.

wildcats, which had been dry at the lower price, profitable and productive. If so, more fields will be developed and the computed averages will be more favorable.

For each price and discount rate the model produces a cash flow stream, annual production of gas and natural gas liquids, and the profitability criteria mentioned above. These are the building blocks used in the second section of the simulator. However, profitability criteria are recomputed in the scenarios; they are not averaged from the basin analyses. Tables 33 through 35 are lists of input data contributed by study participants.

Finally, the estimates of reserves added, production rates, and investment required for an industry effort in all the basins are taken from the scenarios or investment schedules.

The Piceance Basin Example

The foregoing general description of the simulator may be augmented by specific example. Table 36 is a geological data summary for the Fort Union formation in the Piceance basin. The productive area considered is composed of 354 sections out of the 7,100-section basin. The Fort Union formation is divided into six average permeability zones, with area, porosity, and net pay shown for each. Reservoir pressure is 2,100 pounds per square inch absolute (psia) and temperature is 135°F; gas in place can be estimated from these data. The maximum recoverable gas is based on recovery factors intended to compensate for a lack of continuity in flow channels.

TABLE 33

Tight Gas E and P Simulator

Geological Functions

Geological Team

- Select Basin Prospective Area
- List Exploration and Lease Costs
- Select Target Formation(s)
- List Permeability Levels, Percentage of Area
- List Net Pay, Porosity, Pressure, Depth, Temperatures
- Estimate Field Sizes
- Estimate Wildcat Success Ratio

TABLE 34

Tight Gas E and P Simulator

Engineering Functions

Engineering Team

- Run Production Model for

  Initial Production Rate, Decline Rate, and
  30-Year Ultimate Per Well for Each
  Permeability Level

- Provide Cost for

  Drilling
  Surface Equipment
  Massive Fracture
  Operating and Overhead

- Estimate Drilling Schedule for Pipeline Supply Rate

- Estimate NGL (Bbl/MMCF)

TABLE 35

Tight Gas E and P Simulator

Economic Functions

Economic Team

- Responsible for Computer Computations

- Responsible for Basic Profit and Loss Statement

  Local and Federal Taxes
  Working Interest
  Gas Selling Price
  NGL Price
  Discount Rates
  Overhead Costs

- Responsible for Timing of Events in Simulation

TABLE 36

Geological Data Summary

Total Basin Area (Sections): 7100
Type: Lenticular

Basin: Piceance
Subbasin: -
Formation: Ft. Union

Depth (Ft.): 5000
Pressure (PSIA): 2100
Temperature (°F): 135

NGL(BBL/MMCF): 20.

Average Perm. (MD)	Productive Area (Sections)	H/C Gas Porosity (%)	Net Pay Thickness (Ft.)	Estimated Gas in Place at Reservoir Cond. (BCF)	Max. Recoverable Gas (BCF)	For Each Drilling Location W/C: Probability That State of Nature is Productive	Probability that W/C is Productive, Given that State of Nature is Prod. 1st W/C	2nd W/C
0.1	4	7	12	14	11	0.20	1.0	-
0.03	25	6	22	140	107	0.40	1.0	-
0.01	78	5.1	34	573	423	0.45	1.0	-
0.003	131	4.4	48	1,172	805	0.55	1.0	-
0.001	81	3.8	62	809	521	0.65	1.0	-
0.0003	35	3.2	80	380	230	0.75	1.0	-
	354			3,088	2,097			

Data for each drilling location include probability distributions for state of nature, first wildcat, and second wildcat. For the 0.1 md zone, the state of nature is 0.2 productive (and 0.8 dry); i.e., eight out of 10 wildcats drilled in 0.1 md locations will be dry. The probability that the first wildcat drilled in a productive area will be productive is 1.0, and therefore, a second wildcat is not necessary. As net pay increases, the probability that the state of nature will be productive increases.

Table 37 lists production well requirements for both base and advanced cases. Well productivity data are tabulated in Table 38 for the base case and in Table 39 for the advanced case. Note that for the base case the 0.1 md well has the best initial production rate (first year) of all permeabilities, but that production declines rapidly to only 5 million cubic feet per year by the 10th year. Total production for 30 years is only 0.649 BCF. The advanced case 0.1 md well, Table 39, is similar when compared to other advanced case wells. Ultimate production per well from Tables 38 and 39 was used to compute the number of wells per section required to produce all gas in Table 37.

Recoverable gas from actual wells, Table 37, for both base and advanced cases, should be compared to the Maximum Recoverable Gas column in Table 36. The current practice of drilling no more than four wells per section (base case) reduces recoverable gas from 2,097 BCF to 1,130 BCF. In the advanced case, shown in Table 37, reduction in recovery is from the 2,097 BCF available to 1,835 BCF.

Table 42 presents investment and operating expenses. A range of fracture costs exists because net pay thickness increases as permeability decreases, requiring greater volumes of frac fluid and proppant. Advanced case fractures cost more than base case because fracture length is greater for the advanced case.

A discussion of the Fort Union economics summary, Tables 40 and 41, is now appropriate. After the customary identification entries are found rows of entries beginning with "Case Number" and continuing across the page. There are three sets of data corresponding to discount rates of 10, 15, and 20 percent. Each set has gas selling prices of from $1.50 to $12.00/MCF. Case Number 1302111, Table 40, is a base case at a $1.50/MCF price and a 10 percent ROR. It should be emphasized that the entire productive area is drilled in order to evaluate this $1.50 price. Only 13.2 percent of the prospects were profitable. Permeability levels 0.03 md and 0.01 md, coded C and D, came on stream. All other permeabilities were tested but were unprofitable. The investment averaged $1.583 million and the net present value at a 10 percent ROR was -$402 thousand. The DCF ROR was zero. No gas is recoverable in this formation at $1.50/MCF if a 10 percent ROR is required.

It may be asked why the zone with the best permeability, Zone B (0.1 md), was not on stream. A review of its performance on Table 38 shows that this thin formation (12 feet) is inferior to zones at 0.03 and 0.01 md, and therefore, it is not economical.

TABLE 37

PRODUCTION WELL REQUIREMENTS

BASIN: Piceance
SUB-BASIN: -
FORMATION: Ft. Union

PERM. (MD)	BASE CASE: NUMBER OF WELLS/SECTION REQD. TO PRODUCE ALL GAS	BASE CASE: NUMBER OF WELLS/SECTION ACTUALLY USED [MAX=4]	BASE CASE: RECOVERABLE GAS FROM ACTUAL WELLS (BCF)	ADVANCED CASE: NUMBER OF WELLS/SECTION REQD. TO PRODUCE ALL GAS	ADVANCED CASE: NUMBER OF WELLS/SECTION ACTUALLY USED [MAX=12]	ADVANCED CASE: RECOVERABLE GAS FROM ACTUAL WELLS (BCF)
.1	4.5	4	10	3.0	3	11
.03	4.6	4	93	3.2	3	96
.01	5.3	4	321	4.4	4	385
.003	7.7	4	419	6.9	6	700
.001	8.9	4	234	7.1	6	438
.0003	17.4	4	53	13.5	12	205
			1130			1835

TABLE 38

WELL PRODUCTION SUMMARY--BASE CASE

PICEANCE, FORT UNION

GAS PRODUCTION (MMCF/YEAR/WELL)

YEAR	K = 0.3	0.1	0.03	0.01	0.003	0.001	0.0003	0.0001	0.00003	0.00001 (MD)
1		311	228	176	124	110	53			
2		122	117	91	65	57	28			
5		26	58	51	36	33	16			
10		5	30	30	25	22	11			
15		2	17	24	20	18	9			
20		1	7	18	16	15	7			
30		0	2	11	12	11	6			
30-YEAR CUMM. PROD. (MMCF)		649	949	1020	809	719	369			

TABLE 39

WELL PRODUCTION SUMMARY--ADVANCED CASE

PICEANCE, FORT UNION

GAS PRODUCTION (MMCF/YEAR/WELL)

YEAR	K = 0.3	0.1	0.03	0.01	0.003	0.001	0.0003	0.0001	0.00003	0.00001 (MD)
1		348	283	213	149	159	88			
2		161	146	110	75	72	38			
5		60	75	62	42	41	21			
10		16	42	37	28	27	14			
15		6	27	29	21	21	11			
20		2	17	22	16	16	9			
30		0	7	14	11	12	6			
30-YEAR CUMM. PROD. (MMCF)		980	1350	1229	890	899	480			

TABLE 40

ECONOMICS SUMMARY

BASIN Piceance

SUB BASIN

FORMATION Ft. Union

TECHNOLOGY Base

DATE May 1980

CASE NO.	GAS PRICE $/MCF	PROFIT. PROSP. %	K-LEVELS ON STREAM NO.	K-LEVELS ON STREAM VALUE *	AVERAGE PER PROSPECT: E & P INVEST. $M	AVERAGE PER PROSPECT: GAS PROD. BCF	AVERAGE PER PROSPECT: NET PRES. VALUE $M	AVERAGE PER PROSPECT: DCF RATE OF RETURN %	BASIN TOTALS: GAS RECOVER. AT PRICE BCF	BASIN TOTALS: MAX RECOV. GIP BCF	BASIN TOTALS: MAX NO. PROSP. AT PRICE	WELLS: WILDCAT SUCCESS %	WELLS: WILDCAT DRY	WELLS: WILDCAT PROD.	WELLS: DEVELOPMENT DRY	WELLS: DEVELOPMENT PROD.	WELLS: TOTAL
Discount Rate 10%																	
1302111	1.50	13.2	2	CD	1583	1.892	-402	0	-	-	-	13.2	-	-	-	-	-
21	2.50	"	"	"	"	"	-38	9.0	-	-	-	13.2	-	-	-	-	-
31	3.10	30.9	3	CDE	2871	4.176	533	18.4	833	1335	199	30.9	138	61	183	732	1114
41	3.50	47.1	5	BCDEF	5570	7.960	1311	22.9	1077	1867	135	47.1	71	64	264	1054	1453
51	5.00	"	"	"	"	"	2993	39.8	"	"	"	"	"	"	"	"	"
61	7.00	"	"	"	"	"	5236	60.4	"	"	"	"	"	"	"	"	"
71	9.00	55.6	6	BCDEFG	6268	8.426	7719	76.7	1130	2097	134	55.6	59	75	292	1168	1594
81	12.00	"	"	"	"	"	11274	100.4	"	"	"	"	"	"	"	"	"
Discount Rate 15%																	
12	1.50	0	0	-	684	0	-408	0	-	-	-	0	-	-	-	-	-
22	2.50	13.2	2	CD	1583	1.892	-182	9.0	-	-	-	13.2	-	-	-	-	-
32	3.10	30.9	3	CDE	2871	4.176	158	18.4	833	1335	199	30.9	138	61	183	732	1114
42	3.50	"	"	"	"	"	343	22.4	"	"	"	"	"	"	"	"	"
52	5.00	47.1	5	BCDEF	5570	7.960	1746	39.8	1077	1867	135	47.1	71	64	264	1054	1453
62	7.00	"	"	"	"	"	3327	60.4	"	"	"	"	"	"	"	"	"
72	9.00	"	"	"	"	"	4908	78.3	"	"	"	"	"	"	"	"	"
82	12.00	55.6	6	BCDEFG	6268	8.426	7543	100.4	1130	2097	134	55.6	59	75	292	1168	1594
Discount Rate 20%																	
13	1.50	0	0	-	684	0	-413	0	-	-	-	0	-	-	-	-	-
23	2.50	2.0	1	C	836	.260	-376	0	-	-	-	2.0	-	-	-	-	-
33	3.10	13.2	2	CD	1583	1.892	-156	13.8	-	-	-	13.2	-	-	-	-	-
43	3.50	"	"	"	"	"	-81	16.8	-	-	-	"	-	-	-	-	-
53	5.00	47.1	5	BCDEF	5570	7.960	1048	39.8	1077	1867	135	47.1	71	64	264	1054	1453
63	7.00	"	"	"	"	"	2236	60.4	"	"	"	"	"	"	"	"	"
73	9.00	"	"	"	"	"	3427	78.3	"	"	"	"	"	"	"	"	"
83	12.00	55.6	6	BCDEFG	6268	8.426	5384	100.4	1130	2097	134	55.6	59	75	292	1168	1594

* CODE:

B	C	D	E	F	G
0.1	0.03	0.01	0.003	0.001	0.0003

TABLE 41

ECONOMICS SUMMARY

BASIN Piceance

SUB BASIN

FORMATION Ft. Union

TECHNOLOGY Advanced

DATE May 1980

CASE NO.	GAS PRICE $/MCF	PROFIT. PROSP. %	K-LEVELS ON STREAM NO.	K-LEVELS ON STREAM VALUE *	AVERAGE PER PROSPECT: E & P INVEST. $M	AVERAGE PER PROSPECT: GAS PROD. BCF	AVERAGE PER PROSPECT: NET PRES. VALUE $M	AVERAGE PER PROSPECT: DCF RATE OF RETURN %	BASIN TOTALS: GAS RECOVER. AT PRICE, BCF	BASIN TOTALS: MAX RECOV. GIP, BCF	BASIN TOTALS: MAX NO. PROSP. AT PRICE	WELLS: WILDCAT SUCCESS %	WELLS: WILDCAT DRY	WELLS: WILDCAT PROD.	WELLS: DEVELOPMENT DRY	WELLS: DEVELOPMENT PROD.	WELLS: TOTAL
Discount Rate 10%																	
1302211	1.50	0	0	-	852	0	-497	0	-	-	-	0	-	-	-	-	-
21	2.50	13.2	2	CD	1960	2.192	-77	8.4	-	-	-	13.2	-	-	-	-	-
31	3.10	30.9	3	CDE	4582	5.940	693	17.6	1181	1335	199	30.9	138	61	241	965	1405
41	3.50	47.1	5	BCDEF	10196	12.856	2070	22.8	1630	1867	127	47.1	67	60	356	1418	1900
51	5.00	"	"	"	"	"	4871	41.9	"	"	"	"	"	"	"	"	"
61	7.00	"	"	"	"	"	8606	66.3	"	"	"	"	"	"	"	"	"
71	9.00	55.6	6	BCDEFG	13416	14.497	13271	81.7	1835	2097	127	55.6	56	71	447	1788	2362
81	12.00	"	"	"	"	"	19658	112.0	"	"	"	"	"	"	"	"	"
Discount Rate 15%																	
12	1.50	0	0	-	852	0	-501	0	-	-	-	0	-	-	-	-	-
22	2.50	13.2	2	CD	1960	2.192	-246	8.4	-	-	-	13.2	-	-	-	-	-
32	3.10	"	"	"	"	"	-79	12.9	-	-	-	"	-	-	-	-	-
42	3.50	"	"	"	"	"	33	15.8	481	530	219	"	190	29	79	315	613
52	5.00	47.1	5	BCDEF	10196	12.856	2844	41.9	1630	1867	127	47.1	67	60	356	1418	1900
62	7.00	"	"	"	"	"	5479	66.3	"	"	"	"	"	"	"	"	"
72	9.00	"	"	"	"	"	8113	87.8	"	"	"	"	"	"	"	"	"
82	12.00	55.6	6	BCDEFG	13416	14.497	13126	112.0	1835	2097	127	55.6	56	71	447	1788	2362
Discount Rate 20%																	
13	1.50	0	0	-	852	0	-504	0	-	-	-	0	-	-	-	-	-
23	2.50	2.0	1	C	994	.285	-465	0	-	-	-	2.0	-	-	-	-	-
33	3.10	13.2	2	CD	1960	2.192	-215	12.9	-	-	-	13.2	-	-	-	-	-
43	3.50	"	"	"	"	"	-128	15.8	-	-	-	"	-	-	-	-	-
53	5.00	47.1	5	BCDEF	10196	12.856	1717	41.9	1630	1867	127	47.1	67	60	356	1418	1900
63	7.00	"	"	"	"	"	3696	66.3	"	"	"	"	"	"	"	"	"
73	9.00	"	"	"	"	"	5675	87.8	"	"	"	"	"	"	"	"	"
83	12.00	55.6	6	BCDEFG	13416	14.497	9338	112.0	1835	2097	127	55.6	56	71	447	1788	2362

* CODE:

B	C	D	E	F	G
0.1	0.03	0.01	0.003	0.001	0.0003

TABLE 42

INVESTMENT AND OPERATING EXPENSES

BASIN: Piceance
SUB-BASIN: -
FORMATION: Ft. Union

Geology and Geophysics ($/Prospect)	20,000
Drilling Cost ($/Well)	294,000
Fracture Cost ($/Well)	
- Base Case [1000 Ft. Fracture]	142,000 - 282,000
- Advanced Case [2000/4000 Ft. Fracture]	283,000 - 553,000
Surface Equipment ($/Well)	45,000
Annual Operating Expense ($/Well)	10,000
Compressor Fuel Cost, Ratio of Cost to	
W.I. Gas Revenue	.0311

For Case Number 1302121, the gas price is $2.50. Other permeability levels are still uneconomical, but the higher price does bring the DCF ROR to 9.0 percent. The net present value is -$38 thousand at a 10 percent ROR. For the purposes of this study, no gas is available at $2.50.

Continuing with Case Number 1302131 at $3.10, 30.9 percent of the prospects drilled are found to be profitable, and Zone E (0.003 md) has joined Zones C and D as profitable. This increases the gas per prospect to 4.176 BCF for an average investment of $2.871 million. The rate of return is 18.4 percent and the net present value is $533 thousand. From Table 36 it is learned that the maximum recoverable gas for these zones is 1,335 BCF. From Table 37, base case, the recoverable gas from actual wells in these three zones is 833 BCF. These values are shown on Table 40. There are 199 prospects available in the productive area of the basin at the $3.10 price level. This number is obtained by dividing the 833 BCF available by 4.176 BCF per prospect. The program lists the well requirements as 138 dry wildcats, 61 productive wildcats, 183 dry development wells, and 732 producers, for a total of 1,114 wells.

The 15 percent ROR is similar to the 10 percent ROR; however, $3.50 will not bring Zone F on stream at 15 percent as it did at the 10 percent discount rate. At the 20 percent rate, $5.00/MCF is required to turn a profit in the Net Present Value column.

The DCF ROR at $12.00/MCF is 100.4 percent. This brings on all the gas available in the base case for the 15 percent and 20 percent discount rates. The $9.00 price will bring on all gas available at the 10 percent discount rate.

The advanced case, Table 41, is interpreted in the same manner. The amount of gas recoverable in the advanced case at each price should be contrasted with the amount of gas recoverable in the base case. The E and P investment is greater for the advanced case, but rates of return are better than those of the base case.

Piceance Scenario

The Piceance basin example can now be expanded into a scenario of one possible exploration play by the whole industry. In addition to the Fort Union formation at 5,000 feet, other formations analyzed included the Corcoran Cozette at 6,000 feet, the Lower Cretaceous and Jurassic at 7,000 feet, and the Mesaverde at 8,000 feet. Those areas in which the Mesaverde underlies the Fort Union and Corcoran Cozette formations and in which the Corcoran Cozette underlies the Fort Union formation were analyzed separately. Results of these analyses can be found in the Piceance Creek basin chapter of Part II of this report.

Whenever two or more tight gas formations overlap, "stacking" is accomplished by drilling a single well, fracturing each formation separately, and commingling the production. Only those formations within a maximum 3,000-foot separation are stacked in

order to avoid problems due to large formation pressure differences. The total cost of a stacked formation well is the drilling cost for the deepest formation plus the sum of the individual fracture costs.

Stacking was modeled in two different ways. In the Northern Great Plains/Williston basin, the geological data were used to describe multiple formations; that is, the average permeability, porosity, and net pay thickness represent the composite value for all formations penetrated by a well. In the Piceance, Uinta, Wind River, and Greater Green River basins, stacked formations are modeled as follows: the deepest formation is selected as the "target" and the permeability levels and corresponding probability distribution are used to represent the stacked formation. The annual commingled production rate is defined as the production rate of the permeability level penetrated in the target formation plus the expected value of the production rate (over all permeability levels) in each of the other stacked formations. This value is calculated for each of the 30 years of production. Similarly, the ultimate recovery per well is the summation of the ultimate recovery for the permeability level penetrated in the target formation and the expected value of ultimate recovery (over all permeability levels) in each of the other formations.

An example of stacking the Corcoran Cozette (6,000-foot depth) and Mesaverde (8,000-foot depth) formations in the Piceance basin illustrates the calculation. The Corcoran Cozette is the secondary formation and the deeper Mesaverde is the target. Table 43 contains the initial production rates and ultimate recovery per well before stacking. The expected value of production rate in the first year for the Corcoran Cozette over the six permeability levels is 198.5 MMCF per year. The expected value of ultimate recovery per well is 1.871/BCF. Table 44 also shows the resultant initial production rate and the ultimate recovery per well for the stacked formation.

Assume that the subbasin analyses have been completed, and that a play is to be evaluated in the Piceance Creek basin considering all seven areas with a gas selling price of $5.00/MCF and a discount rate of 15 percent. Assume further that base case technology will be employed for the first few years and that advanced technology will be phased in later. This assumption is based on the judgement of research engineers and is illustrated in Table 45. The first set of the seven prospects is the base case, the second is the advanced case. The number of prospects drilled each year for the 20-year development program is shown in the first through 20th columns. There is an overlap of base case and advanced case after the fifth year but the base case is not used after the 10th year in this example. The number of prospects drilled in a formation is the sum of base and advanced prospects.

Table 46 is a summary of the number of prospects drilled and the number of wells required in this play. The annual drilling schedule is shown in Table 47. In a scenario, the number of wells

TABLE 43

Example of Stacked Formations -- Piceance Basin

	Before Stacking					After Stacking	
	Corcoran Cozette Formation			Mesaverde Formation (Target)		Cor-Coz + Mesaverde	
Perm. (md)	Probability of Occurrence	Initial Prod. Rate (MMCF/Year/Well)	Ultimate Recovery (BCF/Well)	Initial Prod. Rate (MMCF/Year/Well)	Ultimate Recovery (BCF/Well)	Initial Prod. Rate (MMCF/Year/Well)	Ultimate Recovery (BCF/Well)
0.3	--	--	--	--	--	--	--
0.1	0.06	353	3.64	573	1.20	772	3.08
0.03	0.22	270	2.77	735	2.18	934	4.05
0.01	0.33	210	1.95	515	2.51	714	4.38
0.003	0.27	141	1.18	359	2.20	558	4.07
0.001	0.09	98	0.76	242	1.60	441	3.48
0.0003	0.03	57	0.42	133	0.90	332	2.77
0.0001	--			94	0.64	293	2.52
0.00003	--			53	0.36	252	2.23
0.00001	--						
	1.00						

$$\text{Expected Value of Initial Production Rate} = \sum_{j=1}^{\text{No. Perm.}} p_j Q_j = 198.5 \text{ MMCF/Yr}$$

$$\text{Expected Value of Ultimate Recovery} = \sum_{j=1}^{\text{No. Perm.}} p_j U_j = 1.871 \text{ BCF}$$

TABLE 44

WELL PRODUCTION SUMMARY--BASE CASE

PICEANCE, MESA VERDE + CORCORAN-COZETTE

GAS PRODUCTION (MMCF/YEAR/WELL)

YEAR	K = 0.3	0.1	0.03	0.01	0.003	0.001	0.0003	0.0001	0.00003	0.00001 (MD)
1		772	934	714	558	441	332	293	252	
2		335	444	386	307	247	191	170	149	
5		132	199	213	185	152	121	110	97	
10		73	106	135	132	110	88	81	73	
15		56	72	101	103	93	75	68	63	
20		48	58	82	90	81	66	61	54	
30		39	44	59	69	66	54	49	45	
30-YEAR CUMM. PROD. (MMCF)		3079	4030	4389	4069	3480	2769	2519	2230	

TABLE 45

SCENARIO 1 — 20 YEAR DEVELOPMENT PROGRAM

		LOCATION OF PROSPECTS-- YEAR OF DEVELOPMENT			1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	
1	1301152	CORCORAN-COZETTE	15.	5.00	1	1	3	4	4	3	3	2	0	0	0	0	0	0	0	0	0	0	0	0	21
2	1302152	FT UNION	15.	5.00	0	1	0	1	0	1	0	1	1	0	0	0	0	0	0	0	0	0	0	0	5
3	1303152	MESA VERDE 8000 FT	15.	5.00	1	2	3	4	5	4	4	3	3	2	0	0	0	0	0	0	0	0	0	0	31
4	1304152	COR-COZ+MESA VERDE	15.	5.00	1	2	2	3	4	4	3	2	1	1	0	0	0	0	0	0	0	0	0	0	23
5	1305152	FT UNION+MESA VERDE	15.	5.00	0	1	2	2	3	4	3	2	1	1	0	0	0	0	0	0	0	0	0	0	19
6	1306152	FT UNION+COR.COZ	15.	5.00	1	1	1	2	3	2	1	1	1	0	0	0	0	0	0	0	0	0	0	0	13
7	1307152	LOWER CRET+JURASSIC	15.	5.00	0	0	1	1	1	2	2	2	1	1	0	0	0	0	0	0	0	0	0	0	11
8	1301252	CORCORAN-COZETTE	15.	5.00	0	0	0	0	0	0	1	1	2	2	5	5	5	5	5	5	5	5	5	5	56
9	1302252	FT UNION	15.	5.00	0	0	0	0	0	0	1	1	1	1	1	1	1	2	2	2	2	2	2	2	20
10	1303252	MESA VERDE 8000 FT	15.	5.00	0	0	0	0	0	0	1	3	4	4	5	5	6	6	8	8	8	8	8	8	82
11	1304252	COR-COZ+MESA VERDE	15.	5.00	0	0	0	0	0	0	1	3	3	3	3	4	4	4	4	4	4	4	4	4	49
12	1305252	FT UNION+MESA VERDE	15.	5.00	0	0	0	0	0	0	1	1	1	1	1	2	2	2	2	2	2	2	3	3	29
13	1306252	FT UNION+COR-COZ	15.	5.00	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	0	1	0	1	1	13
14	1307252	LOWER CRET+JURASSIC	15.	5.00	0	0	0	0	0	0	1	2	2	3	3	3	3	3	3	3	3	4	4	4	41

TABLE 46

SUMMARY OF WELL REQUIREMENTS

	CASE	LOCATION OF PROSPECT			NO. PROSP.	WILDCAT WELLS PROD.	WILDCAT WELLS DRY	WILDCAT WELLS TOTAL	W/C SUCCESS RATIO	DEVELOPMENT WELLS PROD.	DEVELOPMENT WELLS DRY	DEVELOPMENT WELLS TOTAL	TOTAL ALL WELLS
1	1301152	CORCORAN-COZETTE	15.	5.00	21	9	11	20	.48	57	14	71	91
2	1302152	FT UNION	15.	5.00	5	2	2	4	.47	39	9	48	52
3	1303152	MESA VERDE 8000 FT	15.	5.00	31	14	16	30	.46	242	60	302	332
4	1304152	COR-COZ+MESA VERDE	15.	5.00	23	14	8	22	.65	46	11	57	79
5	1305152	FT UNION+MESA VERDE	15.	5.00	19	10	8	18	.57	27	6	33	51
6	1306152	FT UNION+COR.COZ	15.	5.00	13	6	6	12	.52	26	6	32	44
7	1307152	LOWER CRET+JURASSIC	15.	5.00	11	3	7	10	.31	62	15	77	87
8	1301252	CORCORAN-COZETTE	15.	5.00	56	28	27	55	.51	73	18	91	146
9	1302252	FT UNION	15.	5.00	20	9	10	19	.47	223	55	278	297
10	1303252	MESA VERDE 8000 FT	15.	5.00	82	38	43	81	.47	981	245	1226	1307
11	1304252	COR-COZ+MESA VERDE	15.	5.00	49	31	17	48	.65	79	19	98	146
12	1305252	FT UNION+MESA VERDE	15.	5.00	25	11	13	24	.48	73	18	91	115
13	1306252	FT UNION+COR-COZ	15.	5.00	12	6	5	11	.52	14	3	17	28
14	1307252	LOWER CRET+JURASSIC	15.	5.00	41	12	28	40	.31	172	43	215	255

TABLE 47

Annual Drilling Commitment Schedule

	PROSPECT		YEAR	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
1	CORCORAN-COZETTE	15.	5.00	4	4	13	17	17	13	13	8	0	0	0	0	0	0	0	0	0	0	0	0
2	FT UNION	15.	5.00	0	10	0	10	0	10	0	10	10	0	0	0	0	0	0	0	0	0	0	0
3	MESA VERDE 8000 FT	15.	5.00	10	21	32	43	53	43	43	32	32	21	0	0	0	0	0	0	0	0	0	0
4	COR-COZ+MESA VERDE	15.	5.00	3	7	7	10	14	14	10	7	3	3	0	0	0	0	0	0	0	0	0	0
5	FT UNION+MESA VERDE	15.	5.00	0	2	5	5	8	11	8	5	2	2	0	0	0	0	0	0	0	0	0	0
6	FT UNION+COR.COZ	15.	5.00	3	3	3	7	10	7	3	3	3	0	0	0	0	0	0	0	0	0	0	0
7	LOWER CRET+JURASSIC	15.	5.00	0	0	8	8	8	16	16	16	8	8	0	0	0	0	0	0	0	0	0	0
8	CORCORAN-COZETTE	15.	5.00	0	0	0	0	0	0	2	2	5	5	13	13	13	13	13	13	13	13	13	13
9	FT UNION	15.	5.00	0	0	0	0	0	0	14	14	14	14	14	14	14	14	29	29	29	29	29	29
10	MESA VERDE 8000 FT	15.	5.00	0	0	0	0	0	0	15	47	63	63	79	79	95	95	127	127	127	127	127	127
11	COR-COZ+MESA VERDE	15.	5.00	0	0	0	0	0	0	3	9	9	9	9	12	12	12	12	12	12	12	12	12
12	FT UNION+MESA VERDE	15.	5.00	0	0	0	0	0	0	4	4	4	4	4	9	9	9	9	9	9	9	14	14
13	FT UNION+COR-COZ	15.	5.00	0	0	0	0	0	2	2	2	2	2	2	2	2	2	0	2	0	2	0	2
14	LOWER CRET+JURASSIC	15.	5.00	0	0	0	0	0	0	6	12	12	18	18	18	18	18	18	18	18	25	25	25
TOTAL WELLS COMMITTED IN EACH YEAR				20	47	68	100	110	116	139	171	167	149	139	147	163	163	208	210	208	217	220	222

for which funds are committed is listed. This number consists of the wildcats drilled in that year plus development wells to be drilled in the future. Similarly, investments consist of capital and exploration expense in that year and committed to be spent in the future for producing the reserves discovered. Reserve additions are credited in the year the prospect is drilled. Investment requirements and reserve additions are tabulated in Table 48.

TABLE 48

Investment Requirements Committed and Reserve Additions

Year	Investment (MM$)	Gas Reserves Added (BCF)	Cumulative Gas Reserves
1	20.7	43.4	43.4
2	45.6	88.5	131.9
3	65.2	120.8	252.8
4	91.4	172.2	425.0
5	107.8	209.0	633.9
6	108.7	205.5	839.4
7	148.6	250.5	1,089.9
8	198.0	309.4	1,399.4
9	206.2	310.8	1,710.1
10	191.8	281.6	1,991.8
11	185.9	268.5	2,260.3
12	200.2	294.8	2,555.1
13	224.4	323.6	2,878.6
14	224.4	323.6	3,202.2
15	280.3	385.1	3,587.3
16	283.0	394.0	3,981.3
17	280.3	385.1	4,366.4
18	288.2	399.0	4,765.4
19	293.9	401.0	5,166.4
20	296.5	409.9	5,576.3
	3,741.1	Total Investment	

Table 49 is a summary of cash flow and annual production based on the scenario. Natural gas liquids are recovered from the production and tabulated separately. The amount per million cubic feet was supplied by the geologists. The natural gas liquid selling price is set at 5.8 times the gas price (in this case, $29.00 per barrel).

The 69-year project life seems long at first glance. The normal life of a well is 30 years. However, a prospect initiated in the 20th year may have development wells coming on stream 14 years later. Thus, the entire project has a life expectancy of 64 years. The project ends when operating expenses exceed revenue.

Finally, Table 50 lists the profit indicators for the scenario. These are based on an analysis of the scenario cash flow stream and are not averages from the individual formation indicators.

TABLE 49

Cash Flow and Production Summary

YEAR	ANNUAL CASH FLOW (MM$)	CUMUL. CASH FLOW (MM$)	ANNUAL NGL PRODN (MMB)	CUMUL. NGL PRODN (MMB)	ANNUAL GAS PRODN (BCF)	CUMUL. GAS PRODN (BCF)	ANNUAL GAS PRODN (BCF EQ1)	CUMUL. GAS PRODN (BCF EQ1)
1	-.0713	-.0713	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2	-1.1921	-1.2633	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
3	-4.4349	-5.6983	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
4	-6.3982	-12.0965	.0212	.0212	1.2055	1.2055	1.3284	1.3284
5	-6.7556	-18.8521	.0790	.1001	4.4716	5.6771	4.9295	6.2579
6	-2.9813	-21.8334	.1714	.2716	9.8706	15.5476	10.8647	17.1227
7	5.5753	-16.2581	.3036	.5752	17.6662	33.2138	19.4273	36.5500	
8	19.6963	3.4381	.4770	1.0522	27.9780	61.1918	30.7443	67.2943
9	37.7997	41.2379	.6630	1.7151	38.8560	100.0478	42.7013	109.9956
10	55.5485	96.7863	.8719	2.5870	50.9040	150.9518	55.9608	165.9564
11	80.1499	176.9363	1.1336	3.7206	65.5366	216.4883	72.1113	238.0677
12	106.1136	283.0498	1.4093	5.1299	80.9709	297.4593	89.1449	327.2126
13	135.6217	418.6715	1.6800	6.8099	95.7666	393.2259	105.5109	432.7235
14	159.7536	578.4249	1.9056	8.7153	108.7875	502.0134	119.8367	552.5622
15	184.7895	763.2144	2.1295	10.8448	122.1157	624.1292	134.4666	687.0287
16	208.5328	971.7472	2.3499	13.1946	135.6587	759.7879	149.2879	836.3167
17	232.0415	1203.7887	2.5752	15.7698	149.1858	908.9737	164.1218	1000.4385
18	255.6303	1459.6190	2.6206	18.3904	163.5943	1072.5680	179.9538	1180.3922
19	282.8226	1742.4417	3.0866	21.4770	178.9690	1251.5370	196.8715	1377.2638
20	306.4127	2050.8543	3.3495	25.8266	194.0928	1445.6298	213.5201	1590.7838
21	338.1036	2388.9579	3.6133	28.6399	209.1967	1654.8265	230.1541	1820.9379
22	371.5518	2760.5097	3.8711	32.5110	223.9312	1878.7577	246.3835	2067.3214
23	426.4498	3180.9596	4.1337	36.6446	238.8702	2117.6279	262.7572	2330.1668
24	441.0795	3622.0391	4.1524	40.7970	239.6958	2357.3237	263.7797	2593.9465
25	452.5068	4074.5460	4.0186	44.8157	231.8478	2589.1715	255.1558	2849.1023
26	439.7560	4514.3020	3.7798	48.5955	217.7636	2806.9351	239.6864	3088.7887
27	416.5425	4930.8445	3.5361	52.1316	203.6352	3010.7703	224.3488	3313.1335
28	394.1067	5324.9512	3.3244	55.4560	191.6209	3202.3913	211.1025	3524.2359
29	374.3456	5699.2968	3.1300	58.5859	180.0595	3383.4508	199.0133	3723.2493
30	355.3093	6054.6060	2.9405	61.5265	170.2423	3553.6931	187.2973	3910.5466
31	336.1332	6390.7392	2.7550	64.2815	159.8857	3713.5788	175.8649	4086.4115
32	317.2223	6707.9615	2.5765	66.8580	149.9265	3863.5053	164.8700	4251.2815
33	298.5316	7006.5932	2.4074	69.2654	140.4940	4003.9993	154.5434	4405.7307
34	280.5706	7287.1151	2.2510	71.5164	131.7174	4135.7167	144.8730	4550.5117
35	263.4842	7550.5993	2.1075	73.6239	123.6235	4259.3403	135.8473	4686.3590
36	247.3710	7797.9704	1.9746	75.5985	116.0870	4375.4273	127.5398	4813.8988
37	232.2057	8030.1761	1.8525	77.4510	108.1098	4484.5371	118.8542	4933.7529
38	217.6356	8247.8117	1.7413	79.1923	102.6685	4587.2056	112.7679	5046.5208
39	203.0195	8451.4313	1.6411	80.8334	96.7100	4683.9155	106.2263	5152.7471
40	191.1466	8642.5779	1.5503	82.3836	91.1991	4775.1147	100.1907	5252.9378
41	179.4251	8822.5030	1.4691	83.8527	86.2089	4861.3235	94.7294	5347.6672
42	169.2785	8991.7815	1.3937	85.2464	81.4467	4942.7702	89.5301	5437.1973
43	159.1661	9150.9476	1.3225	86.5689	76.8945	5019.6647	84.4991	5521.7644
44	149.7220	9300.6695	1.2548	87.8237	72.6344	5092.2991	79.9122	5601.6766
45	140.9323	9441.6018	1.1915	89.0152	68.6577	5160.9568	75.5686	5677.2452
46	132.5187	9574.2205	1.1320	90.1473	64.8807	5225.8375	71.4465	5748.6916
47	124.6832	9698.8037	1.0753	91.2225	61.2557	5287.0932	67.4922	5816.1838
48	117.3936	9815.9772	1.0214	92.2439	57.7905	5344.8837	63.7145	5879.8984
49	110.0586	9926.0358	.9703	93.2142	54.5637	5399.4473	60.1413	5940.0397
50	103.3151	10029.3510	.9212	94.1354	51.4580	5450.9053	56.8056	5996.8456
51	96.2131	10125.5641	.8686	95.0040	48.1305	5499.0430	53.1762	6050.0669
52	88.7172	10214.2813	.8085	95.8125	44.5831	5543.6269	49.2726	6099.3394
53	80.9530	10295.2343	.7450	96.5575	40.8578	5584.4847	45.1790	6144.5185
54	72.4700	10367.7043	.6743	97.2319	36.7426	5621.2273	40.6537	6185.1722
55	63.3078	10431.0921	.5974	97.8292	32.3314	5653.5588	35.7961	6220.9683
56	54.7629	10485.8550	.5226	98.3518	28.0976	5681.6563	31.1265	6252.0948
57	46.9553	10532.8103	.4511	98.8029	24.0760	5705.7323	26.6923	6278.7871
58	39.3216	10571.8319	.3847	99.1876	20.3912	5726.1235	22.6223	6301.4114
59	32.5873	10604.4193	.3216	99.5092	17.0012	5743.1247	18.8666	6320.2781
60	26.0721	10631.0914	.2654	99.7746	14.0041	5757.1288	15.5434	6335.8215
61	22.1132	10653.2046	.2217	99.9963	11.6859	5768.8147	12.9717	6348.7932
62	17.7979	10670.9125	.1792	100.1754	9.4364	5778.2511	10.4754	6359.2686
63	13.5276	10684.4401	.1306	100.3060	7.2909	5785.5419	8.0945	6367.3631
64	9.9292	10694.3694	.1031	100.4171	5.4220	5790.9639	6.0201	6373.3832
65	6.9777	10701.3471	.0736	100.4907	3.8672	5794.8311	4.2939	6377.6772
66	5.1044	10706.4515	.0539	100.5446	2.8303	5797.6614	3.1430	6380.8202
67	3.3037	10709.9552	.0374	100.5821	1.9636	5799.6250	2.1807	6383.0009
68	2.0653	10712.0405	.0225	100.6045	1.1792	5800.8042	1.3097	6384.3106
69	.9728	10713.0133	.0104	100.6150	.5481	5801.3523	.6085	6384.9191

5801. BCF--MAX GAS PRODUCED IN SCENARIO

TABLE 50

Economic Summary

PROFIT INDICATORS

DISCOUNTED PRESENT WORTH AT 15.0 PCT. (MM$)	401.78075
DCF RATE OF RETURN (PERCENT)	61.20
PAYOUT TIME (YEARS)	6.83
PROFIT PER INVESTMENT ($/$)	2.864
MAX. UNRECOVERED INVESTMENT (MM$)	21.8334
NET CASH RECOVERY AFTER TAX (MM$)	10713.0133
EXPLORATION EXPENDITURE (MM$)	619.9703
PRODUCTION INVESTMENT (MM$)	3163.5398
TOTAL INVESTMENT (MM$)	3741.1497
OPERATING EXPENSE (MM$)	1605.5215

Chapter Five

PRODUCTION RATES AND ADDITIONS TO ULTIMATE RECOVERY

RESERVES AND RESOURCES

The proven reserves estimated by the American Gas Association for U.S. regions as of December 31, 1979, are given in Table 51. These have been combined with the Potential Gas Committee estimates of undiscovered gas, mostly conventional, for December 31, 1978. To these quantities were added the NPC estimates of undiscovered tight gas at a $5.00/MCF price. The NPC total of tight gas in the United States was assumed to be 503 TCF from all 113 basins. The resulting Table 52 indicates a total of about 1,500 TCF of discovered and undiscovered gas yet to be produced in the United States. It indicates that 33 percent of the gas to be produced is tight gas, about 75 percent of which is expected to come from states whose gas potential was largely uneconomical at prices prevailing in the past.

TABLE 51

Regional Proven Reserves*
(TCF)

Southwest		136
Rockies		7
Northern Great Plains		2
Other Lower 48 States		
Eastern	10	
Mid-Continent	2	
Western	6	
Subtotal		18
Subtotal, Lower 48 States		163
Alaska		32
Total		195

*American Gas Association, December 31, 1979.

These proven reserves are combined with estimates of the Potential Gas Committee (Table 53) and the NPC study participants to give the gas estimate in Table 52.

Table 52, which serves as the basis for the annual production of tight gas, is divided into two parts. One part, data for the appraised areas, shows the 231 TCF evaluated in great detail by the study participants; the other part, data for the extrapolated areas, shows the 272 TCF extrapolated by them. The extrapolated areas represent estimates of much lower quality.

TABLE 52

Economically Recoverable U.S. Gas Resources -- Lower 48 States
(TCF)

	Appraised Areas (12 Basins)			Extrapolated Areas (101 Basins)		Total (113 Basins)
Proven Reserves (12-31-79)*	Southwest	Rocky Mountains	Northern Great Plains	Greater Southwest	Other Lower 48 States	
Conventional	9	4	1	119	18	151
Tight†	7	3	1	1	--	12
Undiscovered Gas Potential						
Land Conventional§	54	140	20	268	133	615
Offshore Conventional§	--	--	--	114	105	219
Total Conventional	54	140	20	382	238	834
Tight (NPC)¶	22	113	95	100	172	503
Total Gas	92	260	117	602	428	1,500
Percentage Tight Gas	24	44	81	17	40	33

*American Gas Association (Tables 51 and 53).
†Estimated tight gas portion of January 1, 1979, AGA estimates of proven reserves.
§Potential Gas Committee.
¶At $5.00/MCF (January 1, 1979, dollars), a 15 percent rate of return, and advanced technology and field rules.

TABLE 53

Ultimate U.S. Gas Production Estimate

Class of Gas	Amount (TCF)	Source of Estimate	Date of Estimate
Cumulative Production	573	AGA	December 31, 1979
Proven Reserves	195*	AGA	December 31, 1979
Subtotal	768		
Potential (Undiscovered) Supply		Potential Gas	December 31, 1978
Probable	199	Committee	
Possible	399		
Speculative	421		
Subtotal	1,019†		
Total	1,787		

*5.7 billion barrels of natural gas liquids in addition.
†185 TCF in Alaska and offshore.

EXPLORATION AND PRODUCTION SCENARIOS

A set of scenarios has been written for tight gas production in the 1980-2000 period. These scenarios of gas production are attempts to simulate the actions of the gas industry in developing the tight gas resources.

The gas industry has several parts which interact to determine how much gas will be produced each year. They include:

- The consumers who use gas (e.g., in their furnaces, etc.)
- The companies that distribute gas locally
- The pipeline companies that bring gas from the fields to the towns and cities
- The gas and oil operating companies that find and produce the gas
- The suppliers who furnish materials and services
- The banks that finance investments temporarily through loans
- The investors who furnish permanent capital to the companies

- The various agencies of the government who try to modify the market interaction of the other parts to meet their government's objectives

Some major influences and constraints which are a result of the interaction of these parts have been studied in these scenarios. The usual relationships among the parts of the industry are disrupted and less efficient as the industry tries to respond to threats to the continuity of energy supplies and the transition to new energy sources. These influences are considered mainly as they focus on the gas operators as a group and their individual reactions to the shifting situation.

The scenarios answer some questions of national importance:

- Will higher gas prices cause total U.S. gas production to increase? Or will it cause it to decline more slowly than it would without tight gas production?

- Will higher prices cause larger reserves to become available to meet future U.S. fuel needs?

- Will better technology cause larger reserves to become available to meet future U.S. fuel needs?

- Will changes in pipeline location and capacity be needed to deliver tight gas to the consumer?

- Will drilling tight gas wells divert too much effort from drilling conventional gas wells?

- Will banks and investors be able to supply the capital investment needed for significant levels of tight gas production?

- Will there be a sufficient number of geologists, geophysicists, and geochemists to locate the number of new tight gas prospects needed each year?

- How will individual operators be motivated to accept a new massive fracturing technology? What will get them started making investments in developing the tight gas resource? (Most geologists consider it noncommercial gas and believe the risks are too great to develop it.)

The individual operator must ask himself several questions about entering a tight gas play. Since there are large differences in the sizes of operating companies, the answers will not be the same for all companies.

- Will tight gas remain a resource for a few companies until the technology is standardized?

- Do favorable locations exist where many companies could enter tight gas plays on a low risk basis?

- Will individual operators be able to sell their new gas to a pipeline without several years' delay?
- What percentage of exploration wells should be drilled in tight gas areas?
- Is the profitability great enough for the risks involved?
- Can investors be attracted to finance a tight gas play?
- Can leases be acquired in tight gas areas of superior profitability?

There are about 6,500 operators in the United States who find and produce petroleum in the 113 basins and provinces in the United States that produce gas. The number of gas exploratory wells increased from about 2,000 per year in 1950 to about 6,000 in 1978, and may be as great as 10,000 in 1990.

Many exploration decisions are being made each year, and each is made within the limits of the resources and opportunities of each operator. He will have an inventory of leases available and will probably make his choice of a drillable gas prospect from among them. If his financial resources are small he will tend to drill lower cost, shallow wells or recomplete old wells into tight gas zones. If he has less available technology he will tend to avoid tight gas prospects requiring massive fractures and greater risks.

The technical risk of trying to locate a good permeability stratigraphic trap and successfully fracturing the wells is greater than the risk of a well on a conventional seismic structure.

Another measure of risk is the percentage of drilled prospects that are profitable at the going gas price. Table 54, a comparison from the economics of the Cotton Valley trend, illustrates the degree to which price reduces risk: operators will tend to drill in locations where the risks of unprofitable prospects are smaller.

A third measure of the operator's risk is a comparison of the resources available to companies with the resources required by tight gas plays. Not all operators can afford to drill tight gas prospects.

An estimate of the number of oil and gas wildcat wells drilled annually during the 1970's by operators of various sizes is shown in Table 55. This estimate supports the idea that, in the early years of tight gas development, the more technologically oriented larger operators will be the first to use massive fractures in their gas prospects. Some operators don't drill a sufficient number of wells to risk a large percentage of their exploration budget on a new idea.

Each active operator will examine the opportunities within his area of operation to see if each of the following criteria is met. Figure 25 illustrates the logic process. If he has a ready market or needs to replenish his declining gas reserves, he may budget some tight gas expenditures for the next year. Areas will be selected that have available pipeline capacity. He may have a well, no longer productive, that could be recompleted in a tight gas sand. If drilling rigs are available in these areas, he will allocate some of his capital resources to the tight gas exploration play. As geological evaluations are made, estimates of profitability and risk will be made for prospects within the basins he has chosen. The result of this work will be a list of prospects from which a portfolio of wildcat locations can be chosen.

TABLE 54

Relationship Between Price and Risk
(Cotton Valley Trend, Base Case)

Price ($/MCF)	Percentage Prospects Profitable
$1.50	6
2.50	18
3.50	26
5.00	34
7.00	34
9.00	42
12.00	58

TABLE 55

Oil and Gas Wildcat Wells Drilled

Size of Operator (Rank Order)	Exploratory Oil and Gas Wells Per Year Per Operator	Total Exploratory Oil and Gas Wells Per Year for Group	Percentage of Exploratory Wells Drilled by Group
1 - 100	21	2,100	26
101 - 200	5	500	6
201 - 400	3	600	8
401 - 1,000	1.7	1,000	13
1,001 - 6,500	0.7	3,800	47
		8,000	100

Geologists and investors can find details about basin and formation characteristics for 12 basins in the chapters of Part II of this report. The basic data on net pay, porosity, production rates, probability of success, investment requirements, and average rates of return for 82 subbasins are given in tables and discussed. The economic data may be used to make a rough ranking of these subbasins and to select the best areas for potential prospects.

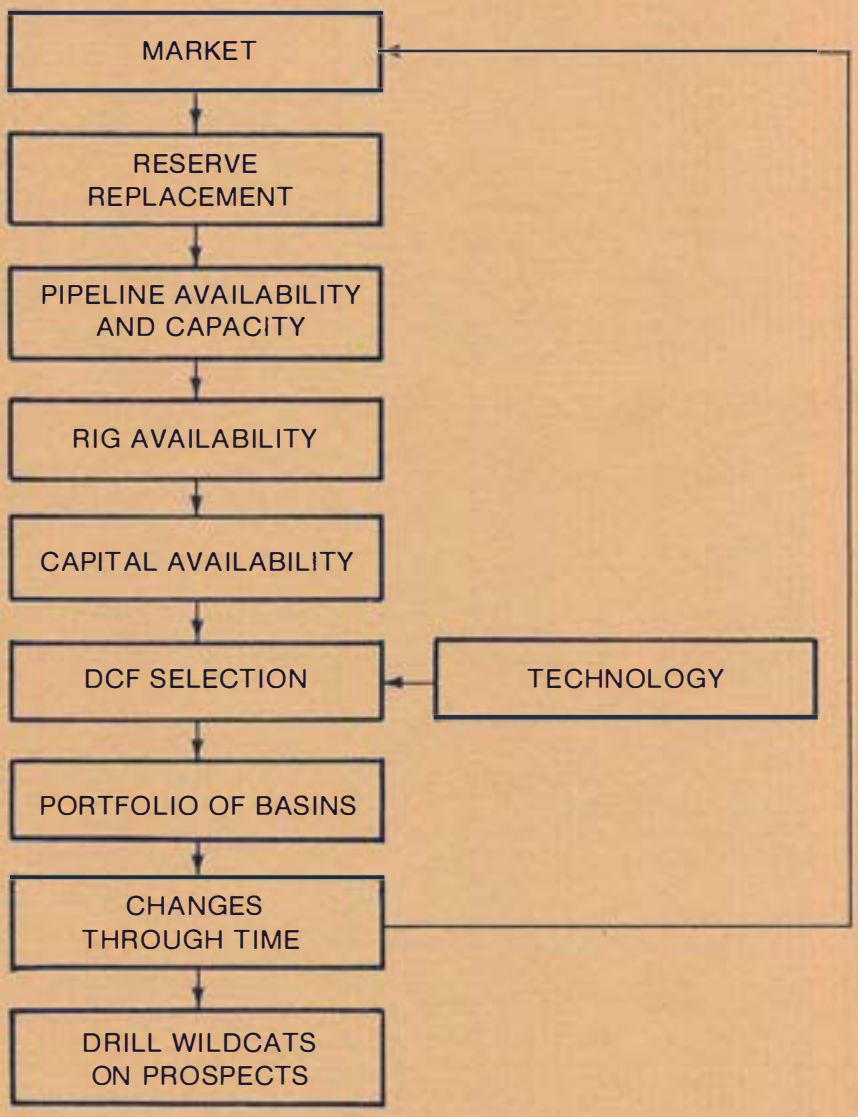


Figure 25.

Tight gas is widespread in favorable formations. Economic tight gas is found only in the better quality reservoir rock. The field boundaries are not set by structural traps but by permeability and economics.

The production from gas wells completed in tight sands initially declines very rapidly and then follows a much slower and more stabilized rate of decline throughout the remaining producing life of the well. Table 56 is an example which gives annual production

TABLE 56

WELL PRODUCTION SUMMARY--BASE CASE

SAN JUAN, DAKOTA

GAS PRODUCTION (MMCF/YEAR/WELL)

YEAR	K = 0.4	0.1	0.04	0.01	0.004	0.001	0.0004	0.0001	0.00004	0.00001 (MD)
1			131	86	62	32	20			
2			84	53	35	17	10			
5			59	34	23	10	6			
10			46	26	17	8	5			
15			38	23	15	7	4			
20			31	21	14	6	3			
30			23	18	12	5	3			
30-YEAR CUMM. PROD. (MMCF)			1323	827	556	263	155			

estimates from the various permeability areas in the Dakota sand of the San Juan basin. The permeabilities range from 0.04 to 0.0004 md; the cumulative production in 30 years of continuous flow ranges from 155 to 1,323 MMCF per well. These wells produce at very low rates. It will be necessary to drill from four to 12 wells per section to recover a substantial part of this gas.

Table 57 shows how the permeability and net pay of the formation affect the price required to produce the gas. The example is for the lower quality part of the Dakota sand in the San Juan basin. The location is northwestern New Mexico.

The average permeabilities (k) of different parts of the basin range from 0.04 to 0.0004 md. The number of sections with these average permeabilities is shown in the first column. The net pay is given in feet (h) and the product of permeability and net pay (kh) is expressed in millidarcy-feet (md-ft). As the kh value declines, the price required to bring those sections having the next lower kh value into production must increase. For example, a $3.10/MCF price is necessary to produce the gas from formations having a kh of 0.15. Formations having a kh of 0.40 or greater could be produced at $2.50/MCF. The 75 sections productive at $2.50 would yield 142 BCF. Recoverable resources could be increased by 321 BCF to 463 BCF by raising the price to $3.10. Those wildcats drilled on prospects in the 225 sections with a kh of 0.15 would now be producers instead of dry holes.

The calculation forms the basis for the projection of large increases in gas resources as price increases. Table 58 illustrates the consequence of each gas price. The first column shows the gas price. The third column shows how the area that is producible increases from 75 sections at $2.50/MCF to 1,040 sections at $9.00/MCF. The fifth column shows how the recoverable gas resource increases over 12 times for the same price change.

The average rate of return for all the successful and unsuccessful prospects drilled is shown in the seventh column. The marginal rate of return for this case is 15 percent. Any wildcat well that would not make a 15 percent rate of return was considered below the marginal rate of return; it was thus considered a dry hole and abandoned. The average rate of return for a group of producing fields would naturally be higher than 15 percent since only the poorest quality fields in the group would make this low a return. As the price rises, the proportion of higher quality reservoir increases and the average rate of return increases, although the marginal rate is 15 percent. Note that at $2.50/MCF, the average rate of return was 9.6 percent; it was all below the marginal rate and none of the gas would be produced if the 15 percent marginal rate were insisted upon. Note also that at a $12.00/MCF price no additional gas is produced and the rise in price from $9.00/MCF only increases the average rate of return for the set of fields that were profitable at $9.00/MCF.

TABLE 57

Economics of the Dakota Formation -- San Juan Basin, New Mexico
Current Technology -- 15 Percent DCF ROR

Number of Sections in Basin	Effective Gas Permeability (Millidarcies,k)	Net Pay (Ft, h)	Reservoir Quality (Md-Ft, kh)	Gas Price ($/MCF)	Gas In Place (BCF/Section)	Gas Recovery at Prices (BCF/Section)	Percentage Recovery $\left(\frac{\text{Gas Recovered}}{\text{Gas In Place}}\right) \times 100$
75	0.04	10	0.40	2.50	2.46	1.89	77
150	0.01	15	0.15	3.10	2.95	2.14	73
515	0.004	20	0.08	5.00	2.95	2.00	68
300	0.001	25	0.025	9.00	2.76	1.75	64
148	0.0004	30	0.012	>12.00	2.21	1.30	59
1,188							

TABLE 58

Economics of the Dakota Formation -- San Juan Basin, New Mexico
(Current Technology - 15 Percent DCF ROR)

Gas Price ($/MCF)	Reservoir Quality (Md-Ft)	Number of Sections Productive at a Profit	Incremental BCF Produced at a Profit For this Reservoir Quality	Total BCF Produced at a Profit	Percentage of Wildcat Prospects Profitable	Average DCF ROR	Gas Resources Lost to Use at This Price (BCF)
2.50	0.40	75	142	142	6.2	9.6	1,763
3.10	0.15	225	321	463	17.6	18.5	1,442
5.00	0.08	740	1,031	1,494	56.2	32.7	411
9.00	0.025	1,040	318	1,812	76.9	59.9	193
More than 12.00	0.012	1,040	0	1,812	76.9	91.4	193

In order to make these kinds of choices for a scenario of a whole industry, the scheme described herein was followed. The discounted cash flow rate of return for each subbasin was chosen as the major criterion.

The prospects to be proven and fully or partially developed in the first 20 years in each subbasin were selected as follows. Prospects in a subbasin that on average would produce a 50 percent DCF ROR would be preferred, and 40 percent of the prospects in that subbasin would be initiated in the first 20 years. Of these, 24 percent would be initiated in the first decade and 16 percent in the second decade. During the next century, the remaining 60 percent would be explored and drilled. The guidelines for other rates of return are shown in Table 59. The advanced case technology phase-in schedule for blanket and lenticular sands is shown in Table 60.

TABLE 59

Investment Guideline for Standard Scenario
Percentage of Total Prospects in Subbasin
Initiated in Three Time Periods

Percent DCF	Years 1 - 10	Years 11 - 20	Next Century
50	24	16	60
40	12	18	70
30	2	18	80
20	0.5	9.5	90
10	0	0	100

These guidelines were used to write a standard scenario based on a $5.00/MCF gas price and a 15 percent DCF ROR. Other scenarios follow the standard pattern but differ in price and discount rates. The standard scenario for $5.00/MCF and a 15 percent ROR and for $3.50/MCF and a 15 percent ROR are displayed in Appendix E.

Several scenarios have been provided and are listed in Table 61. The standard scenario at $5.00/MCF and a 15 percent ROR assumes production of 8.3 TCF of tight gas in the year 2000; the half-standard scenario produces about half as much, and the twice-standard scenario produces about twice as much.

Scenarios are also provided at prices of from $2.50 to $9.00/MCF and standard scenarios for 10 and 20 percent marginal rates of return.

Production rates for the standard scenario at $5.00/MCF and a 15 percent ROR are given in Table 62. This scenario produces about 2 TCF per year by 1990, 5 TCF per year by 1995, and 8.3 TCF in the year 2000. This scenario provides a reachable goal for U.S. production of tight gas.

TABLE 60

Percentage of Prospects
Using Advanced Technology

Year	Blanket	Lenticular
1981	0	0
1982	0	0
1983	5	0
1984	10	0
1985	30	0
1986	50	5
1987	70	10
1988	90	30
1989	100	50
1990	100	70
1991	100	90
1992	100	100
1993	100	100
1994	100	100
1995	100	100
1996	100	100
1997	100	100
1998	100	100
1999	100	100
2000	100	100

TABLE 61

Variations on the Standard Production Scenario

Gas Price ($/MCF)	2.50	3.50	5.00	9.00
Marginal DCF Rate of Return				
10%		Standard	Standard	
15%	Half-Standard	Standard	Half-Standard Standard Twice-Standard Recompletion Case	Standard
20%			Standard	

TABLE 62

Standard Scenario

Year 1981 ($5.00 @ 15%)

	Pro-duction (TCF/Yr.)	Production Cumulative (TCF)	Invest-ment ($ Bill.)	No.Pro-spects /Yr.	No.Wells /Yr.	Reserves Added (TCF/Yr.)	Reserves Cumula-tive (TCF)	Percent 500 TCF Produced	Percent 500 TCF Added to Reserve
No.Gr.Plains/Will.	0	0	.021	10	67	.077	.077	0	0.02
Eastern	0	0	.215	42	391	.312	.312	0	0.06
Western	0	0	.236	52	401	.354	.354	0	0.07
Mid-Continent	0	0	.021	3	55	.031	.031	0	0.01
Gr. Southwest	0	0	.186	29	213	.363	.363	0	0.07
Rocky Mts.	0	0	.266	59	269	.494	.494	0	0.10
Total	0	0	0.994	202	1,468	1.72	1.72	0	0.35

TABLE 62 (Continued)

Standard Scenario

Year 1985 ($5.00 @ 15%)

	Production (TCF/Yr.)	Production Cumulative (TCF)	Investment ($ Bill.)	No. Prospects /Yr.	No. Wells /Yr.	Reserves Added (TCF/Yr.)	Reserves Cumulative (TCF)	Percent 500 TCF Produced	Percent 500 TCF Added to Reserves
No. Gr. Plains/Will.	0.003	0.004	0.243	89	686	0.728	1.774	0.00	0.35
Eastern	0.022	0.027	0.953	187	1,792	1.499	4.166	0.01	0.83
Western	0.028	0.036	0.401	94	651	0.630	2.127	0.01	0.43
Mid-Continent	0.002	0.002	0.080	17	238	0.140	0.468	0.00	0.09
Gr. Southwest	0.025	0.036	0.387	55	419	0.783	2.765	0.01	0.55
Southwest	0.008	0.010	0.354	48	315	0.741	1.705	0.00	0.34
Rocky Mts.	0.076	0.102	0.797	180	799	1.556	5.326	0.02	1.07
Total	0.164	0.217	3.565	670	4,900	6.077	18.331	0.05	3.660

TABLE 62 (Continued)

Standard Scenario

($5.00 @ 15%)

Year 1990

	Production (TCF/Yr.)	Production Cumulative (TCF)	Investment ($ Bill.)	No. Prospects /Yr.	No. Wells /Yr.	Reserves Added (TCF/Yr.)	Reserves Cumulative (TCF)	Percent 500 TCF Produced	Percent 500 TCF Added to Reserves
No.Gr.Plains/Will.	0.126	0.289	0.518	321	996	1.387	8.313	0.06	1.67
Eastern	0.350	0.949	1.565	132	2,676	2.470	14.695	0.19	2.94
Western	0.220	0.680	0.785	171	1,085	1.114	7.199	0.14	1.44
Mid-Continent	0.027	0.074	0.132	28	318	0.250	1.487	0.01	0.30
Gr.Southwest	0.257	0.720	2.443	288	2,621	5.435	18.326	0.14	3.67
Southwest	0.201	0.476	0.694	78	626	1.477	8.723	0.10	1.74
Rocky Mts.	0.589	1.949	1.441	256	1,081	0.274	15.205	0.39	3.04
Total	1.770	5.137	6.953	1,274	9,403	12.407	73.948	1.03	14.53

TABLE 62 (Continued)

Standard Scenario

Year 1995 ($5.00 @ 15%)

	Production (TCF/Yr.)	Production Cumulative (TCF)	Investment ($ Bill.)	No. Prospects /Yr.	No. Wells /Yr.	Reserves Added (TCF/Yr.)	Reserves Cumulative (TCF)	Percent 500 TCF Produced	Percent 500 TCF Added to Reserves
No.Gr.Plains/Will.	0.443	1.866	0.674	266	1,343	1.777	16.691	0.37	3.33
Eastern	0.833	4.256	0.763	155	1,110	1.445	21.695	0.85	4.34
Western	0.479	2.676	0.571	74	571	0.712	10.617	0.54	2.12
Mid-Continent	0.071	0.335	0.111	24	197	0.227	2.562	0.07	0.51
Gr.Southwest	1.610	5.461	3.475	408	3,194	7.709	54.257	1.09	10.85
Southwest	0.552	2.572	0.543	58	476	1.133	15.161	0.51	3.03
Rocky Mts.	1.191	6.676	2.184	313	1,509	2.961	28.978	1.34	5.80
Total	5.229	23.842	8.321	1,298	8,400	16.014	149.961	4.77	29.98

TABLE 62 (Continued)

Standard Scenario

Year 2000 ($5.00 @ 15%)

	Production (TCF/Yr.)	Production Cumulative (TCF)	Investment ($ Bill.)	No. Prospects /Yr.	No. Wells /Yr.	Reserves Added (TCF/Yr.)	Reserves Cumulative (TCF)	Percent 500 TCF Produced	Percent 500 TCF Added to Reserves
No.Gr.Plains/Will.	0.778	5.079	0.663	205	1295	1.770	25.639	1.02	5.13
Eastern	0.975	8.811	0.824	163	1185	1.563	29.287	1.76	5.86
Western	0.524	5.178	0.571	74	571	0.712	14.177	1.04	2.84
Mid-Continent	0.114	0.823	0.082	24	157	0.183	3.658	0.17	0.73
Gr.Southwest	3.373	18.954	3.153	389	2696	7.172	92.265	3.79	18.45
Southwest	0.757	6.007	0.543	58	476	1.133	20.825	1.20	4.16
Rocky Mts.	1.772	14.448	2.113	309	1545	2.676	43.206	2.89	8.64
Total	8.293	59.300	7.949	1222	7925	15.209	229.057	11.87	45.810

TABLE 62 (Continued)

Standard Scenario

Year 2005 ($5.00 @ 15%)

	Production (TCF/Yr.)	Production Cumulative (TCF)	Investment ($ Bill.)	No. Prospects /Yr.	No. Wells /Yr.	Reserves Added (TCF/Yr.)	Reserves Cumulative (TCF)	Percent 500 TCF Produced	Percent 500 TCF Added to Reserve
No.Gr.Plains/Will.	1.09	9.89	1.41	445	2,879	3.55	40.14	1.98	8.03
Eastern	1.24	14.33	2.89	473	3,867	4.83	48.09	2.87	9.62
Western	0.60	8.01	1.09	173	1,232	1.45	19.83	1.6	3.97
Mid-Continent	0.14	1.48	0	0	0	0	3.66	0.30	0.73
Gr. Southwest	3.85	38.68	0	0	0	0	92.26	7.74	18.45
Southwest	0.77	10.02	0	0	0	0	20.83	2.0	4.17
Rocky Mts.	2.14	24.43	3.56	571	2,818	4.44	61.66	4.89	12.33
Total	9.83	106.84	8.95	1,662	10,796	14.27	286.47	21.38	57.30

TABLE 62 (Continued)

Standard Scenario

Year 2010 ($5.00 @ 15%)

	Pro-duction (TCF/Yr.)	Production Cumulative (TCF)	Invest-ment ($ Bill.)	No.Pro-spects /Yr.	No.Wells /Yr.	Reserves Added (TCF/Yr.)	Reserves Cumula-tive (TCF)	Percent 500 TCF Produced	Percent 500 TCF Added to Reserve
No.Gr.Plains/Will.	1.67	16.92	1.87	587	3,793	4.73	61.77	3.38	12.35
Eastern	2.18	23.14	3.79	635	5,053	6.35	77.44	4.63	15.49
Western	0.89	11.77	1.33	214	1,497	1.80	28.49	2.35	5.7
Mid-Continent	0.11	2.09	0	0	0	0	3.66	0.42	0.73
Gr. Southwest	2.87	54.80	0	0	0	0	92.26	10.96	18.45
Southwest	0.60	13.33	0	0	0	0	20.83	2.67	4.17
Rocky Mts.	2.95	37.44	4.09	637	3,104	4.48	84.85	7.49	16.97
Total	11.27	159.49	11.08	2,073	13,447	17.36	369.30	31.90	73.86

TABLE 62 (Continued)

Standard Scenario

Year 2015 ($5.00 @ 15%)

	Pro-duction (TCF/Yr.)	Production Cumulative (TCF)	Invest-ment ($ Bil.)	No.Pro-spects /Yr.	No.Wells /Yr.	Reserves Added (TCF/Yr.)	Reserves Cumula-tive (TCF)	Percent 500 TCF Produced	Percent 500 TCF Added to Reserve
No.Gr.Plains/Will.	2.47	27.64	1.41	447	2,840	3.58	82.75	5.53	16.55
Eastern	3.41	37.77	2.87	492	3,842	4.74	105.68	7.55	21.14
Western	1.21	17.22	1.24	195	1,385	1.72	37.56	3.44	7.51
Mid-Continent	0.09	2.60	0	0	0	0	3.66	0.52	0.73
Gr. Southwest	2.25	67.16	0	0	0	0	92.26	13.43	18.45
Southwest	0.47	15.92	0	0	0	0	20.83	3.18	4.17
Rocky Mts.	3.56	54.27	2.58	440	1,776	2.43	102.37	10.85	20.47
Total	13.46	222.57	8.10	1,574	9,843	12.47	445.11	44.50	89.02

TABLE 62 (Continued)

Standard Scenario

Year 2020 ($5.00 @ 15%)

	Production (TCF/Yr.)	Production Cumulative (TCF)	Investment ($ Bil.)	No.Prospects /Yr.	No.Wells /Yr.	Reserves Added (TCF/Yr.)	Reserves Cumulative (TCF)	Percent 500 TCF Produced	Percent 500 TCF Added to Reserve
No.Gr.Plains/Will.	2.97	41.72	0.74	173	1,487	1.86	95.33	8.34	19.06
Eastern	4.05	57.13	1.73	337	2,385	2.94	124.21	11.43	24.84
Western	1.37	23.87	0.67	102	717	0.91	43.76	4.77	8.75
Mid-Continent	0.08	3.03	0	0	0	0	3.66	0.61	0.73
Gr. Southwest	1.80	77.05	0	0	0	0	92.26	15.41	18.45
Southwest	0.38	18.00	0	0	0	0	20.83	3.60	4.17
Rocky Mts.	3.34	71.73	1.69	313	1,110	1.40	110.79	14.35	22.16
Total	14.00	363.81	4.83	925	5,699	7.11	490.84	58.51	98.16

The standard scenario has been extended to include exploration through 2020 with production continuing through 2070. Table 62 for the year 2020 shows cumulative production of 364 TCF with cumulative reserves added of 491 TCF. This accounts for 98 percent of the estimated reserves and 58.5 percent of production. Cumulative reserves added, production, and investment for the standard scenario are shown in graph form in Figure 26. Annual production is plotted on Figure 27.

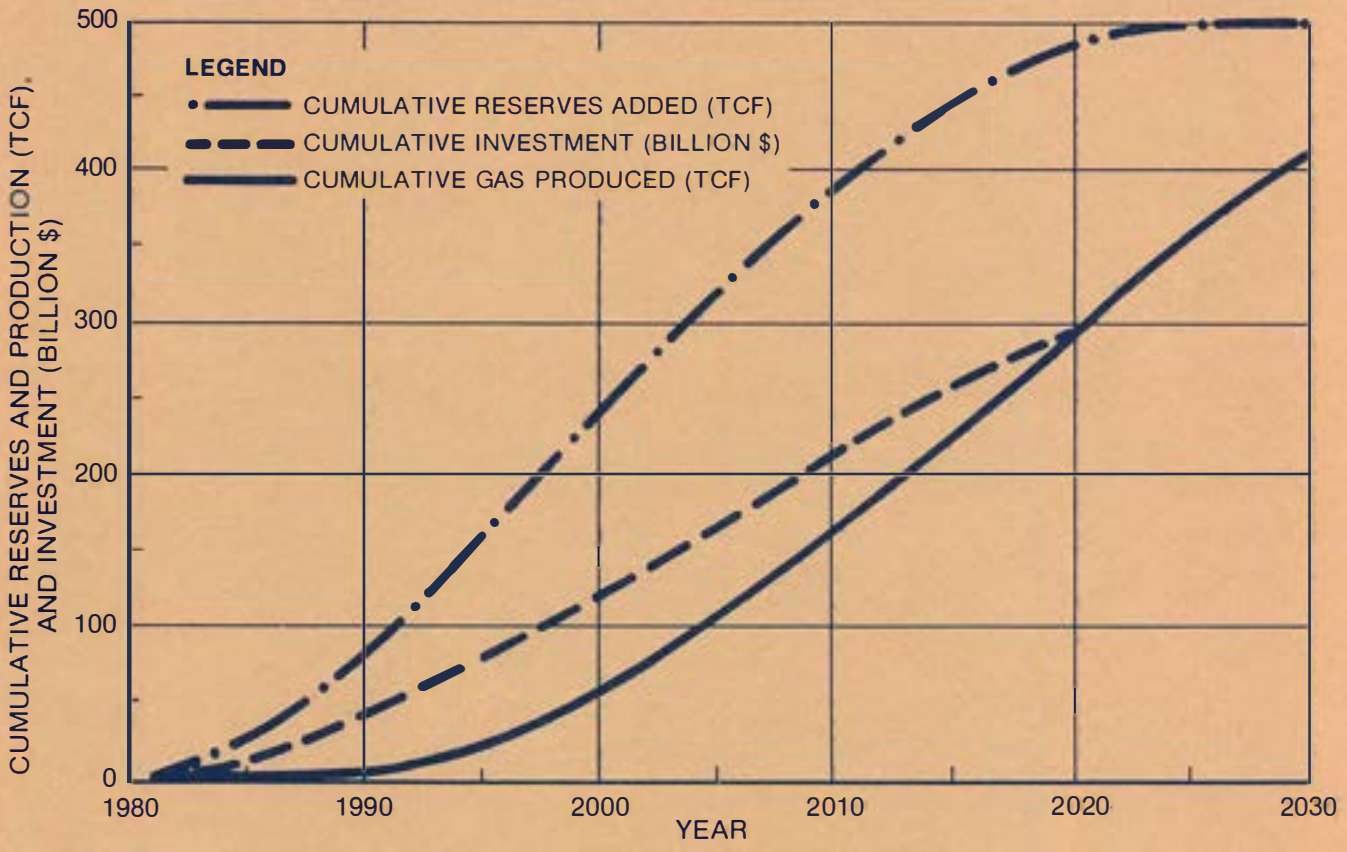


Figure 26. Standard Scenario, Cumulative Reserves, Production, and Investment Committed.

Entries in Table 62 need further explanation. Production is credited to the year in which it occurs. Thus, in 1981 production is zero; in 1985 production is low because the basin model assumes a three-year delay between project initiation and production start-up. Entries in the Number of Prospects Per Year column are correctly credited to the year shown. However, the Number of Wells Per Year column is a consolidated statement of the number of wells that will be drilled or committed and investment to be made in the future due to the number of prospects initiated. Likewise, Resources Added are credited to the year the prospects are initiated. The final two columns are percentages based on production and reserves added as a portion of the 503 TCF ultimate assumed for this study.

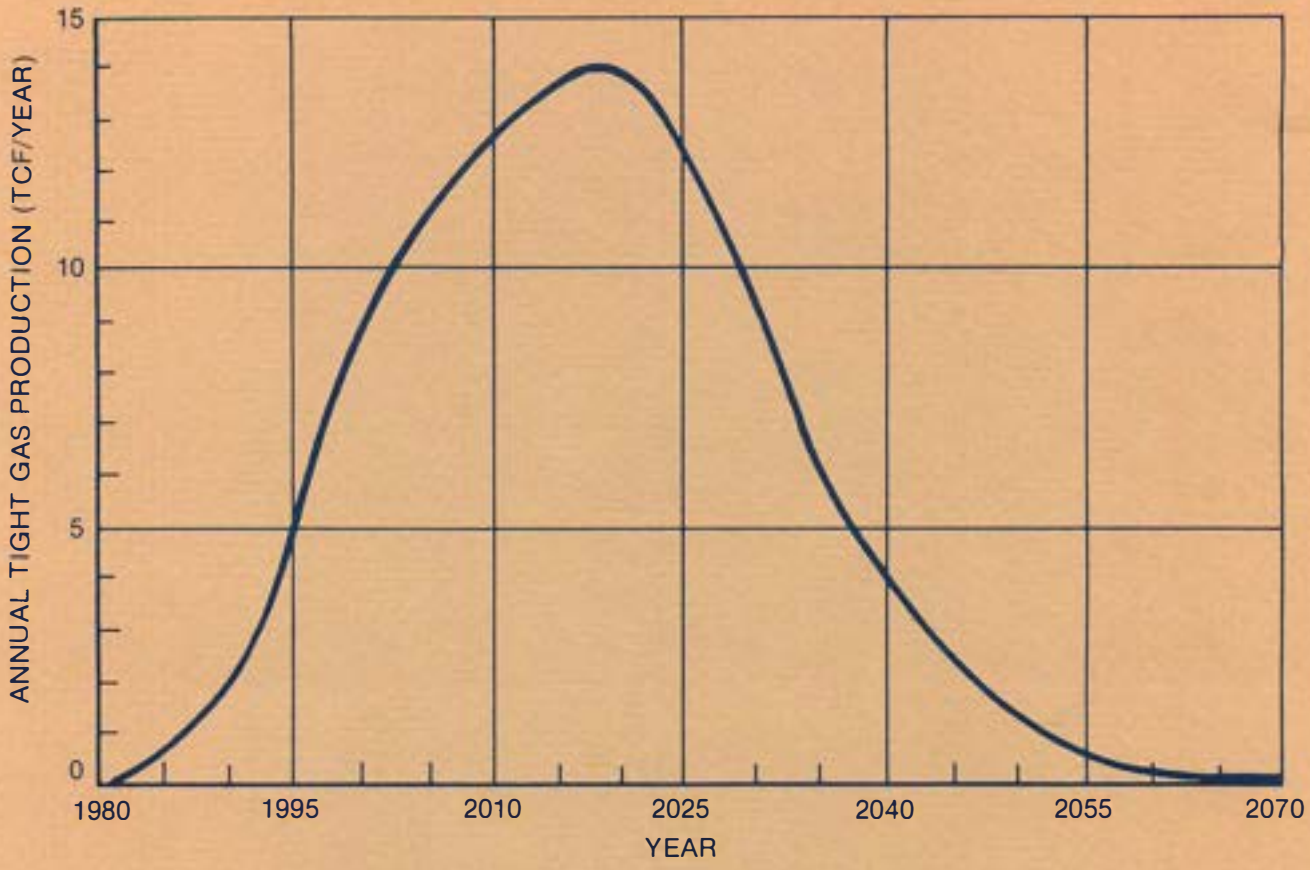


Figure 27. Lifetime Production Rates for 500 TCF of Tight Gas—Standard Scenario, Annual Production 1981-2070.

The half-standard scenario shown in Table 63 produces about 1 TCF in 1990 and 4 TCF in the year 2000. This could easily be accomplished.

The twice-standard scenario shown in Table 64 produces about 2.2 TCF in 1990 and 15.6 TCF in the year 2000. Production at this level could replace a substantial amount of imported oil, but it could be difficult to achieve.

Scenarios were compared with several criteria to estimate their influence on the U.S. energy supply. As an approximate guide to the various components of the gas supply, Table 65 was prepared.[1] A composite forecast was made reflecting various opinions about future developments.

Criterion No. 1 Produce enough tight gas sands to maintain a 22 TCF per year production rate.

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[1]Energy Information Administration, 1979 Annual Report to Congress, Vol. 3, Table S-2, p. X; Unconventional Gas Sources, National Petroleum Council, 1980; forecasts of various U.S. oil and gas operators.

TABLE 63

Half-Standard Scenario

Year 1981 ($5.00 @ 15%)

	Production (TCF/Yr.)	Production Cumulative (TCF)	Investment ($ Bill.)	No. Prospects /Yr.	No. Wells /Yr.	Reserves Added (TCF/Yr.)	Reserves Cumulative (TCF)	Percent 500 TCF Produced	Percent 500 TCF Added to Reserves
No. Gr. Plains/Will.	0.	0.	0.007	3	21	0.025	0.025	0.	0.01
Eastern	0.	0.	0.093	19	169	0.140	0.140	0.	0.03
Western	0.	0.	0.102	23	175	0.152	0.152	0.	0.03
Mid-Continent	0.	0.	0.014	2	36	0.020	0.020	0.	0.00
Gr. Southwest	0.	0.	0.088	14	104	0.174	0.174	0.	0.03
Southwest	0.	0.	0.032	4	43	0.054	0.054	0.	0.01
Rocky Mts.	0.	0.	0.109	24	106	0.202	0.202	0.	0.04
Total	0	0	0.445	89	654	0.767	0.767	0	0.15

TABLE 63 (Continued)

Half-Standard Scenario

Year 1985 ($5.00 @ 15%)

	Production (TCF/Yr.)	Production Cumulative (TCF)	Investment ($ Bill.)	No. Prospects /Yr.	No. Wells /Yr.	Reserves Added (TCF/Yr.)	Reserves Cumulative (TCF)	Percent 500 TCF Produced	Percent 500 TCF Added to Reserves
No.Gr.Plains/Will.	0.001	0.002	0.123	45	338	0.364	0.843	0.00	0.17
Eastern	0.011	0.013	0.468	93	881	0.738	2.091	0.00	0.42
Western	0.013	0.017	0.200	47	333	0.315	1.069	0.00	0.21
Mid-Continent	0.001	0.001	0.043	9	121	0.071	0.227	0.00	0.04
Gr.Southwest	0.013	0.017	0.188	27	228	0.372	1.388	0.00	0.28
Southwest	0.004	0.006	0.186	25	174	0.388	0.840	0.00	0.17
Rocky Mts.	0.035	0.046	0.434	96	424	0.860	2.764	0.00	0.55
Total	0.078	0.102	1.642	342	2499	3.108	9.222	0.00	1.840

TABLE 63 (Continued)

Year 1990

Half-Standard Scenario

($5.00 @ 15%)

	Production (TCF/Yr.)	Production Cumulative (TCF)	Investment ($ Bill.)	No. Prospects /Yr.	No. Wells /Yr.	Reserves Added (TCF/Yr.)	Reserves Cumulative (TCF)	Percent 500 TCF Produced	Percent 500 TCF Added to Reserves
No. Gr. Plains/Will.	0.060	0.135	0.242	79	456	0.653	4.076	0.03	0.82
Eastern	0.176	0.477	0.769	148	1,314	1.206	7.350	0.10	1.47
Western	0.110	0.337	0.391	76	540	0.560	3.606	0.07	0.72
Mid-Continent	0.013	0.037	0.058	12	147	0.108	0.756	0.01	0.15
Gr. Southwest	0.130	0.359	1.220	144	1,307	2.713	9.191	0.07	1.84
Southwest	0.101	0.237	0.350	39	323	0.743	4.364	0.05	0.87
Rocky Mts.	0.314	1.006	0.783	127	555	1.123	8.006	0.20	1.60
Total	0.904	2.588	3.813	625	4,642	6.393	37.349	0.53	7.470

TABLE 63 (Continued)

Half-Standard Scenario

Year 1995 ($5.00 @ 15%)

	Production (TCF/Yr.)	Production Cumulative (TCF)	Investment ($ Bill.)	No. Prospects /Yr.	No. Wells /Yr.	Reserves Added (TCF/Yr.)	Reserves Cumulative (TCF)	Percent 500 TCF Produced	Percent 500 TCF Added to Reserves
No.Gr.Plains/Will.	0.217	0.912	0.340	119	671	0.899	8.156	0.18	1.63
Eastern	0.416	2.132	0.399	76	568	0.744	10.855	0.43	2.17
Western	0.240	1.336	0.290	37	283	0.362	5.266	0.27	1.05
Mid-Continent	0.037	0.169	0.058	12	100	0.118	1.307	0.03	0.26
Gr.Southwest	0.807	2.739	1.740	204	1599	3.858	27.138	0.55	5.43
Southwest	0.275	1.285	0.268	29	224	0.562	7.570	0.78	1.51
Rocky Mts.	0.598	3.459	1.021	130	708	1.373	14.196	0.69	2.84
Total	2.590	12.032	4.116	607	4153	7.916	74.488	2.90	14.89

TABLE 63 (Continued)

Half-Standard Scenario

($5.00 @ 15%)

Year 2000

	Production (TCF/Yr.)	Production Cumulative (TCF)	Investment ($ Bill.)	No. Prospects /Yr.	No. Wells /Yr.	Reserves Added (TCF/Yr.)	Reserves Cumulative (TCF)	Percent 500 TCF Produced	Percent 500 TCF Added to Reserves
No.Gr.Plains/Will.	0.382	2.482	0.354	120	694	.929	12.903	0.50	2.58
Eastern	0.487	4.409	0.410	82	596	.785	14.639	0.88	2.93
Western	0.261	2.571	0.270	36	276	.341	7.035	0.51	1.41
Mid-Continent	0.057	0.419	0.055	13	98	.114	1.880	0.08	0.38
Gr.Southwest	1.685	9.485	1.722	203	1,568	1.722	46.366	1.90	9.27
Southwest	0.379	3.003	0.275	29	248	.571	10.406	0.60	2.08
Rocky Mts.	0.852	7.200	1.188	180	839	1.583	21.761	1.44	4.35
Total	4.103	28.569	4.274	663	4,319	6.045	114.990	5.910	23.00

TABLE 64

Twice-Standard Scenario

($5.00 @ 15%)

Year 1981

	Production (TCF/Yr.)	Production Cumulative (TCF)	Investment ($ Bill.)	No. Prospects /Yr.	No. Wells /Yr.	Reserves Added (TCF/Yr.)	Reserves Cumulative (TCF)	Percent 500 TCF Produced	Percent 500 TCF Added to Reserves
No.Gr.Plains/Will.	0.	0.	0.021	10	67	0.077	0.077	0.	0.02
Eastern	0.	0.	0.215	42	391	0.312	0.312	0.	0.06
Western	0.	0.	0.236	52	401	0.354	0.354	0.	0.07
Mid-Continent	0.	0.	0.021	3	55	0.031	0.031	0.	0.01
Gr.Southwest	0.	0.	0.186	29	213	0.363	0.363	0.	0.07
Southwest	0.	0.	0.049	7	72	0.089	0.089	0.	0.02
Rocky Mts.	0.	0.	0.439	119	360	1.263	1.263	0.	0.25
Total	0.	0.	1.167	262	1559	2.489	2.489	0.	0.577

TABLE 64 (Continued)

Twice-Standard Scenario

Year 1985 ($5.00 @ 15%)

	Production (TCF/Yr.)	Production Cumulative (TCF)	Investment ($ Bill.)	No. Prospects /Yr.	No. Wells /Yr.	Reserves Added (TCF/Yr.)	Reserves Cumulative (TCF)	Percent 500 TCF Produced	Percent 500 TCF Added to Reserves
No.Gr.Plains/Will.	0.003	0.004	0.257	97	715	0.761	1.832	0.00	0.37
Eastern	0.022	0.027	1.259	245	2,278	2.126	4.965	0.01	0.99
Western	0.028	0.036	0.448	103	700	0.718	2.215	0.01	0.44
Mid-Continent	0.002	0.002	0.080	17	238	0.140	0.468	0.00	0.09
Gr.Southwest	0.025	0.036	0.387	55	419	0.783	2.765	0.01	0.55
Southwest	0.008	0.010	0.354	48	315	0.741	1.705	0.00	0.34
Rocky Mts.	0.135	0.240	0.968	208	912	1.821	6.504	0.05	1.30
Total	0.223	0.355	3.753	773	5,577	7.090	20.454	0.08	4.08

TABLE 64 (Continued)

Twice-Standard Scenario

Year 1990 ($5.00 @ 15%)

	Production (TCF/Yr.)	Production Cumulative (TCF)	Investment ($ Bill.)	No. Prospects /Yr.	No. Wells /Yr.	Reserves Added (TCF/Yr.)	Reserves Cumulative (TCF)	Percent 500 TCF Produced	Percent 500 TCF Added to Reserves
No.Gr.Plains/Will.	0.154	0.324	2.204	709	4,381	5.685	20.896	0.06	4.18
Eastern	0.508	1.190	3.740	673	5,795	6.350	32.476	0.24	6.50
Western	0.267	0.747	1.328	218	1,592	1.747	9.679	0.15	1.94
Mid-Continent	0.027	0.074	0.132	28	318	0.250	1.487	0.01	0.30
Gr.Southwest	0.257	0.720	2.443	288	2,621	5.435	18.326	0.14	3.67
Southwest	0.201	0.476	0.694	78	626	1.477	8.723	0.10	1.74
Rocky Mts.	0.801	2.633	4.200	721	3,207	5.540	26.307	0.53	5.26
Total	2.215	6.164	14.741	2,715	18,540	26.484	117.894	1.23	23.59

TABLE 64 (Continued)

Twice-Standard Scenario

($5.00 @ 15%)

Year 1995

	Production (TCF/Yr.)	Production Cumulative (TCF)	Investment ($ Bill.)	No. Prospects /Yr.	No. Wells /Yr.	Reserves Added (TCF/Yr.)	Reserves Cumulative (TCF)	Percent 500 TCF Produced	Percent 500 TCF Added to Reserves
No.Gr.Plains/Will.	1.256	3.988	2.742	889	5,545	6.998	54.513	0.80	10.90
Eastern	2.057	8.578	4.059	789	5,740	7.444	66.372	1.72	13.27
Western	0.764	3.632	1.712	222	1,720	2.136	19.732	0.73	3.95
Mid-Continent	0.071	0.335	0.111	24	197	0.227	2.562	0.07	0.51
Gr.Southwest	1.610	5.461	3.475	408	3,194	7.709	54.257	1.09	10.85
Southwest	0.552	2.572	0.543	58	476	1.133	15.161	0.51	3.03
Rocky Mts.	2.439	11.226	5.930	976	4,369	6.913	60.318	2.25	12.06
Total	8.749	35.792	18.572	3,366	21,241	32.560	272.915	7.17	54.57

TABLE 64 (Continued)

Twice-Standard Scenario

Year 2000 ($5.00 @ 15%)

	Production (TCF/Yr.)	Production Cumulative (TCF)	Investment ($ Bill.)	No. Prospects /Yr.	No. Wells /Yr.	Reserves Added (TCF/Yr.)	Reserves Cumulative (TCF)	Percent 500 TCF Produced	Percent 500 TCF Added to Reserves
No.Gr.Plains/Will.	2.681	14.633	1.911	623	3,836	4.929	83.906	2.93	16.78
Eastern	3.471	23.087	4.281	862	6,088	7.898	105.141	4.62	21.03
Western	1.184	8.721	1.712	225	1,720	2.136	30.413	1.74	6.08
Mid-Continent	0.114	0.823	0.082	24	157	0.183	3.658	0.17	0.73
Gr.Southwest	3.373	18.954	3.153	389	2,696	7.172	92.265	3.79	18.45
Southwest	0.757	6.007	0.543	58	476	1.133	20.825	1.20	4.16
Rocky Mts.	4.001	28.444	5.077	745	3,653	5.562	90.906	5.69	18.18
Total	15.581	100.669	16.759	2,926	18,626	29.013	427.114	20.14	85.41

TABLE 65

Energy Information Administration (EIA) 1979 Forecast of U.S. Gas Supplies*
(TCF)

EIA	1978	1985	1990	1995	2000	2010	2020
Conventional Lower 48	18.4	16.1	14.6	12.4	11.3	9.5	7.3
Alaska	0.2	0.2	1.1	1.4	1.6	1.9	1.8
Unconventional	0.9	1.9	3.0	4.0	3.4	3.2	3.1
Tight Gas	0.8	1.8	2.8	3.8	3.2	3.0	2.9
Devonian Shale Gas	0.1	0.1	0.2	0.2	0.2	0.2	0.2
Synthetics	0.0	0.1	0.1	0.1	0.1	0.5	1.3
Imports	0.9	0.8	0.8	0.8	0.7	0.2	0.1
Total Gas Supply	20.4	19.1	19.6	18.7	17.2	15.3	13.5
Percentage U.S. Supply from Tight Gas	4%	9%	14%	20%	19%	20%	23%
NPC							
Unconventional Developed Before 1980†	0.9	0.5	0.3	--	--	--	--
Unconventional (@ $5.00/MCF) Developed After 1980§	0.0	0.6	3.1	8.6	11.5	13.5	14.9
Tight Gas	0.0	0.2	1.8	5.2	8.3	11.3	14.0
Devonian Shale Gas	0.0	0.3	0.7	0.8	0.9	0.7	0.3
Coal Seam Gas	0.0	0.1	0.6	2.6	2.3	1.5	0.6
Geopressured Gas	0.0	0.004	0.006	0.008	0.008	0.0	0.0
Total Gas Supply¶	20.4	18.3	20.0	23.3	25.3	25.6	25.3
Percentage U.S. Supply from New Tight Gas	0%	1%	9%	22%	33%	44%	55%

*EIA 1979 Annual Report to Congress, with lower portion of table revised to substitute NPC estimate for unconventional gas.

†Includes declining production from 1978 unconventional gas reserves not otherwise shown in NPC study.

§Price in constant January 1, 1979, dollars.

¶EIA forecast with substitution of NPC unconventional gas projections.

Table 65 indicates that the 22 TCF per year peak rate for 1973 could be possible with the standard scenario between 1990 and 1995. The half-standard scenario would achieve this goal by the year 2000 and the twice-standard scenario would achieve it by 1995.

Criterion No. 2 Replace a significant number of oil imports with tight gas.

Table 66 projects the U.S. energy supply for the 1980-2020 period. In making this projection, the EIA considered estimated prices for each kind of energy and its potential supply. The projections reflect interfuel competition for markets. Accepting this projection as a reasonable case, it indicates a rather steady oil

TABLE 66

Projected U.S. Energy Supply*
(Quadrillion Btu/Yr or TCF/Yr)

	1978	1980	1985	1990	1995	2000	2010	2020
Domestic Oil	20.7	20.5	18.7	19.6	19.4	20.5	20.6	15.0
Oil Imports	16.7	15.0	12.1	11.7	11.8	13.1	8.4	6.8
Domestic Gas	19.5	19.0	18.2	18.7	17.8	16.4	14.6	12.1
Gas Imports	0.9	1.6	0.8	0.8	0.8	0.7	0.2	0.1
Coal	15.0	17.6	25.0	29.3	36.7	38.2	49.7	71.6
Nuclear	3.0	2.9	5.6	8.2	9.6	11.3	18.1	21.8
Renewable, Solar, and Other	2.6	1.4	1.2	0.8	0.4	7.9	12.4	16.0
Total	78.4	78.0	81.6	89.1	96.5	108.1	124.0	143.4
World Oil Price								
Mid-1979 $/Bbl	15.50	31.00	32.00	37.00	41.00	43.00	43.00	43.00
January 1, 1979, $/MCF Equivalent Gas Price	2.52	4.92	5.08	6.02	6.51	6.83	6.83	6.83

*U.S. Energy Information Administration (EIA) 1979 Annual Report to Congress, Table S-2, p. X.

import rate in the range of 12 to 13 quadrillion Btu (TCF equivalent) per year in the 1985-2000 period. Gas declines from 19 to 13 quadrillion Btu per year during the same period. This decline suggests that coal will be replacing gas due to market price competition and the law requiring more coal to be burned in utility furnaces. NPC gas supply estimates are compared with EIA estimates in Table 65 which indicate a growing gas supply in excess of the EIA projections. If this excess gas competes on market price with imported oil, the imports could be reduced drastically. The NPC gas supply projection is based on a $5.00/MCF price while the equivalent price of oil imports rises from $5.53 in 1985 to $6.99 in 2020.

The potential import replacement schedule is indicated in Table 67 and Figure 28. It may not be desirable to eliminate oil imports altogether, but this appears to be a practical and economical alternative by 2005. Before this occurred, the world market price of oil could decline to be competitive with tight gas, probably about $5.00/MCF in January 1, 1979, dollars, or $30.70 per barrel in mid-1979 dollars.

The half-standard scenario could take longer and the twice-standard scenario could take less time to make these import reductions.

WELL RECOMPLETION SCENARIO

Opportunities exist in the southwestern United States for tight reservoir recompletions in existing wells. These wells are to be found in depleted conventional fields where production facilities are in place. Pipeline capacity exists for transmission to markets.

The evaluation used assumed that a depleted well might be recompleted in a tight reservoir by running a suite of logs to locate the productive zones, recementing casing, and testing for gas shows at a cost of $100,000. The probability of success is assumed to be greater than wildcat exploration because the recompleted well already has some logs in the tight gas zone and is in a known productive area. The recompleted well is charged a cost for MHF but not a drilling cost. Three more wells per section are drilled and treated as development wells at base case costs. Production starts as soon as each well is completed.

Table 68 is an economic summary of recompletions in the southwestern United States at a $5.00 price and a 15 percent marginal rate of return. Maximum gas recovered is 16.4 TCF out of 21.7 maximum recoverable gas in place. This is 75 percent, and is more profitable because the recompleted wells are less expensive than similar wells drilled and completed in the target formations. Also, net present value is higher for recompletions because production (and revenue) starts in the year the wells are completed.

TABLE 67

Percentage Replacement of Imported Oil By
Potential Gas Production Above EIA Demand Estimate
(Quadrillion Btu or TCF/Year)

Year	NPC	EIA	Excess Gas	Imported Oil	Percentage Replaced by Gas
1985	18.3	19.1	0.0	12.1	0
1990	20.0	19.6	0.4	11.7	3
1995	23.3	18.7	4.6	11.8	39
2000	25.3	17.2	8.1	13.1	62
2010	25.6	15.3	10.3	8.4	>100
2020	25.3	13.5	11.8	6.8	>100

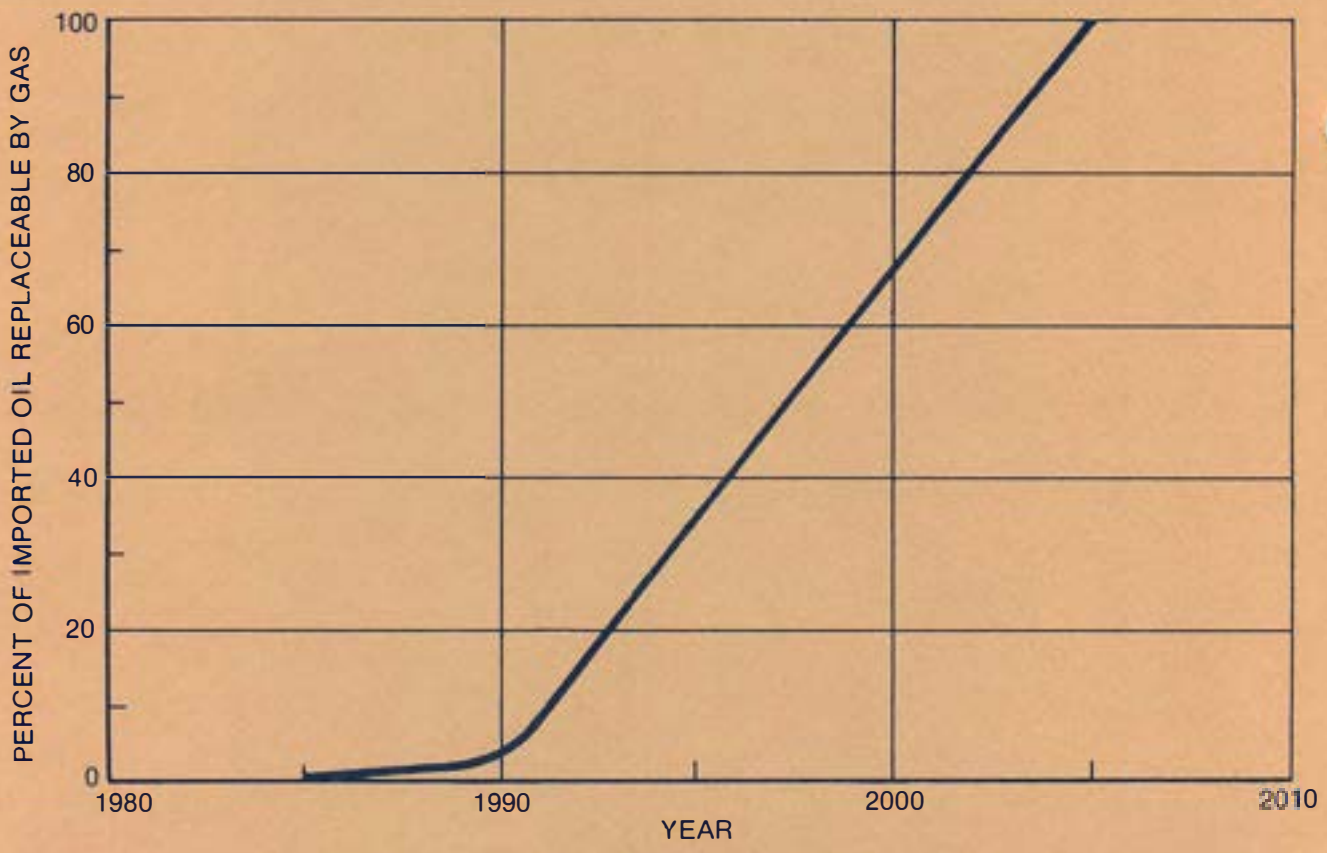


Figure 28. Potential Replacement of Oil Imports by Excess Gas Supply
(Standard Scenario).

Figure 29 compares the production rates between recompletion and half-standard scenario rates. The number of prospects is the same in each scenario. The figure combines production from two areas, Southwest United States and Greater Southwest United States. Greater Southwest United States is extrapolated from the southwestern United States according to the schedule at the bottom of Table 68.

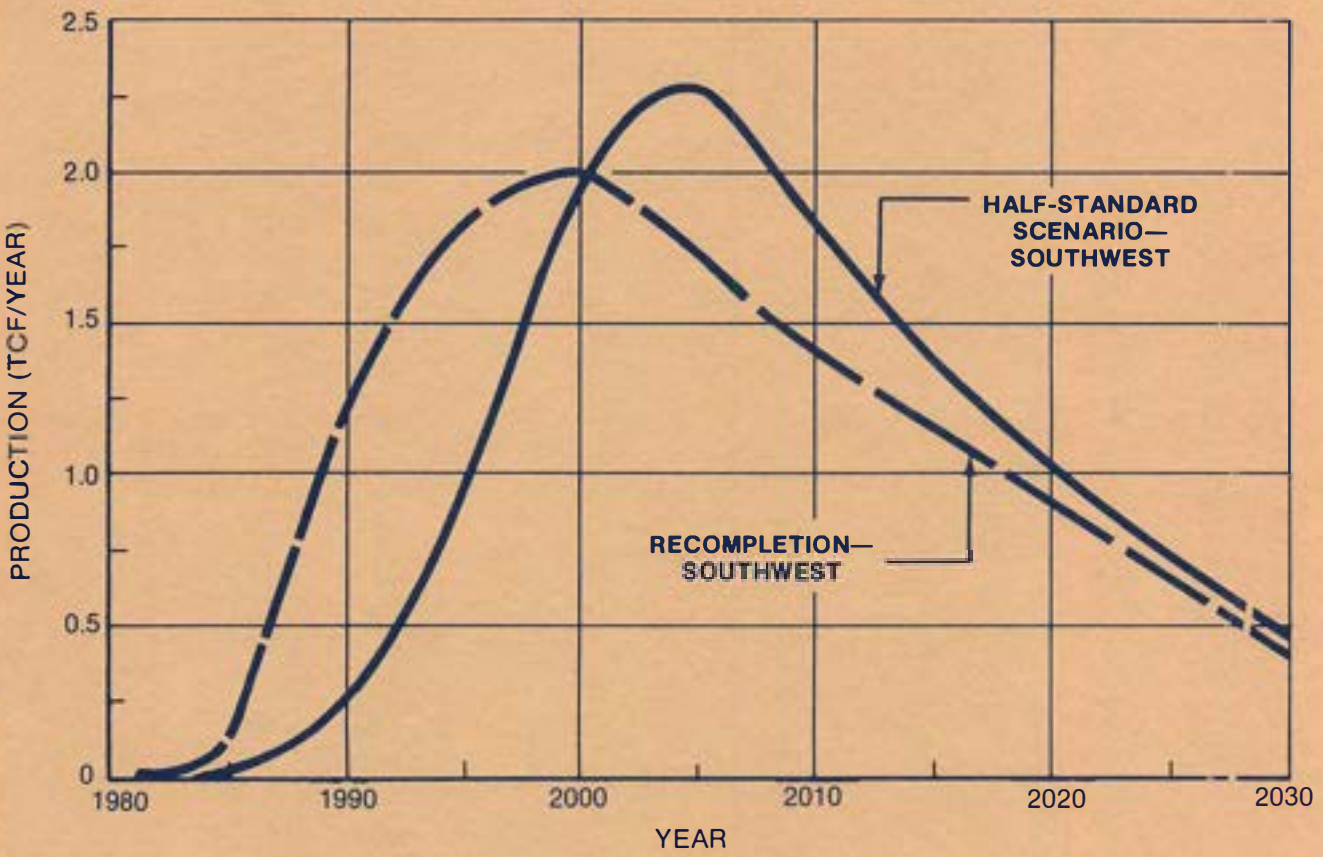


Figure 29. Comparison of Recompletion Production Rate with the Half-Standard Scenario Rate for Southwest United States.

The FERC has set an incentive price also for recompletion of old oil and gas wells into tight gas formations. Since most of these already have pipeline connections, production can begin immediately after the well is completed. A scenario has been written for the Southwest region for recompletion prospects. It shows increased production about five years earlier than the standard scenarios based on new field wildcats.

In the Southwest alone, the recompletion scenario indicates an average increase in production of nearly 0.9 TCF per year in the 1990-1995 period, as shown in Table 69.

When Southwest region recompletions are incorporated into the half-standard scenario for the entire United States, the projected production is very similar to the EIA estimate in Figure 30.

TABLE 68

Economic Summary of Southwest Recompletions

($5.00/MCF; 15 Percent DCF ROR)

Southwestern Region — Technology Base Case

Basins Listed below** — Formation See below** — Date October 1980

Case No.	Gas Price $/MCF	Profit Prosp. Percentage	K-Levels On Stream No.	Value*	Average Per Prospect: E & P Invest. $M	Gas Prod. BCF	Net Pres. Value $M	DCF Rate of Return Percentage	Basin Totals: Gas Recover. At Price BCF	Max. Recov. GIP, BCF	Max. No. Prosp. At Price	Wells: Wildcat Success Percentage	Wildcat Dry	Wildcat Prod.	Development Dry	Development Prod.	Total
Discount Rate 15 Percent																	
1601152**	5.00	55.2	3	CDE	11,643	15.525	4,434	31.2	1,494	1,494	96	47.7	58	53	558	2,231	2,900
1801152	5.00	66.0	7	A-G	12,137	17.873	3,837	32.8	688	1,613	38	53.2	22	25	242	969	1,259
2101152	5.00	65.0	8	A-H	8,028	21.669	11,114	89.5	7,292	9,795	337	59.3	150	219	593	2,370	3,331
2201152	5.00	80.5	7	ABCDEFG	4,850	18.151	10,274	122.4	2,423	3,098	133	59.1	74	107	92	369	642
2202152	5.00	78.6	7	ABCDEFG	13,674	27.481	11,356	60.4	4,375	5,353	159	57.9	91	125	132	528	876
2301152	5.00	48.3	4	CDEF	6,652	8.587	1,206	22.8	156	371	18	34.6	9	17	68	271	365
																	9,373

Case #	Southwest	Greater Southwest
**1601152	San Juan Dakota	New Mexico-West Texas
1801152	Val Verde Sonora	Central Texas
2101152	Cotton Valley Trend	East Texas - Louisiana
2201152	Edwards Lime S.W.	Texas Gulf South
2202152	Edwards Lime Central	Texas Gulf Central
2301152	Val Verde Ozona	Oklahoma

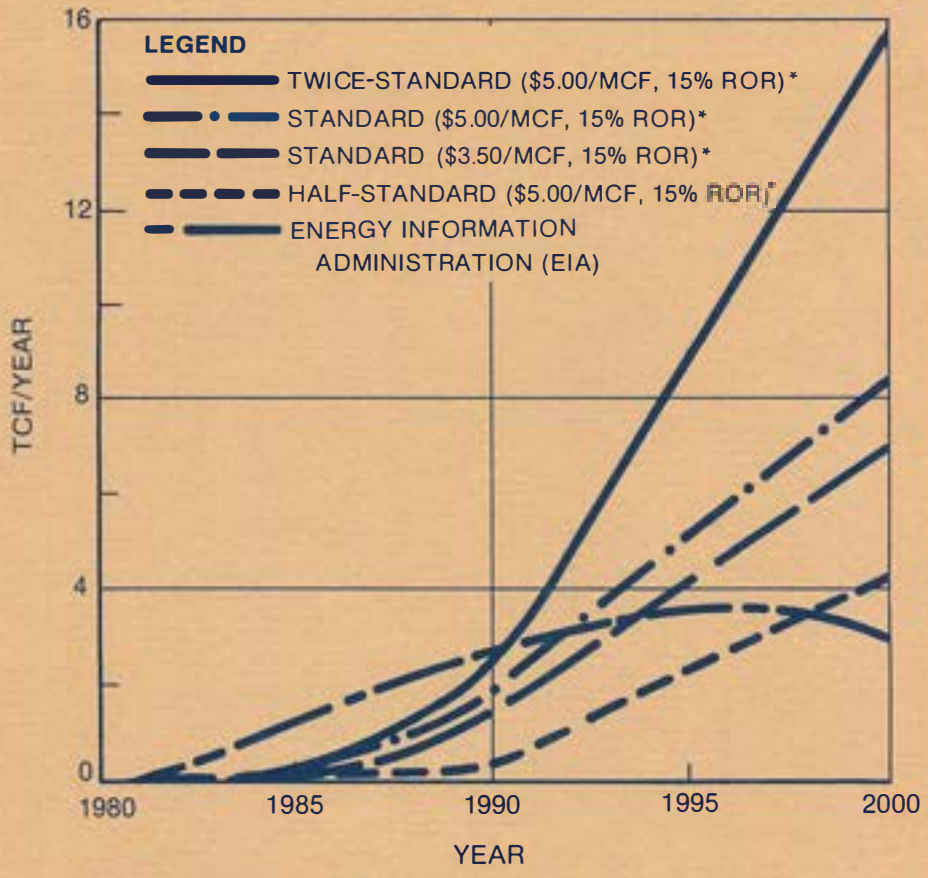
*CODE:

A	B	C	D	E	F	G
0.3	0.1	0.03	0.01	0.003	0.001	0.0003

TABLE 69

Recompletion Scenario vs. New Field Wildcats
(Southwest)

Year	Half-Standard Old Well Recompletion Scenario	Half-Standard New Field Wildcats Scenario	Additional Production
1985	0.101	0.017	0.084
1990	1.195	0.231	0.964
1995	1.849	1.082	0.767
2000	1.994	2.064	-0.070
2005	1.671	2.311	-0.640
2030	0.427	0.454	-0.027



*Constant January 1, 1979, dollars.

Figure 30. Tight Gas Production Rates—Comparison of Scenarios.

The production for the half-standard scenario was modified to replace new field wildcat production in the Southwest region by production from tight gas zones discovered by recompleting old wells. The U.S. production for these cases is compared with the EIA forecast in Table 70.

TABLE 70

Well Recompletions and New Field Wildcats vs.
EIA Tight Gas Estimates
(TCF)

Year	EIA Forecast	NPC Half-Standard Scenario: Recompleted Wells in Southwest and New Field Wildcats Elsewhere	NPC Half-Standard Scenario: All New Field Wildcat
1985	1.8	0.15	0.078
1990	2.8	1.868	0.904
1995	3.8	3.357	2.590
2000	3.2	4.033	4.103

SPECIAL PURPOSE SCENARIOS

In addition to the scenarios used in estimating future production from tight gas reservoirs, special purpose scenarios have been developed. The objective of these scenarios is to study the effects of price, discount rate, and technology on the amount of gas recoverable without the practical constraints imposed by drilling rig availability, pipeline capacity, etc.

One such scenario set is illustrated in Figures 31 through 34. Here base case technology can be compared with advanced case technology at three different price levels. These data are for the appraised basins only and are based on the assumption that all resources available at the stated price are discovered in the 20-year period 1981-2000.

These data are summarized in Tables 71 through 73. The effects due to change in marginal rate of return (discount rate) are added to Tables 71 and 72.

The graphs in Figures 35 through 37 show similar data. Figure 35 permits a comparison of production for a 15 percent discount rate at $2.50, $3.50, $5.00, and $9.00/MCF. Figure 36 shows production at $5.00/MCF at discount rates of 10, 15, and 20 percent. Figure 37 shows production at a 10 percent discount rate for $3.50 and $5.00/MCF.

More detailed information is contained in Tables E-3 through E-6. These tables show production by basin for the 12 appraised basins. Tables E-3 and E-5 illustrate a 15 percent discount rate and $2.50/MCF and $3.50/MCF respectively. Tables E-4 and E-6 illustrate a 10 percent discount rate and $3.50/MCF and $5.00/MCF.

Another special scenario is composed of four regions: Southwest, Other Southwest, Rocky Mountains, and Northern Great Plains/

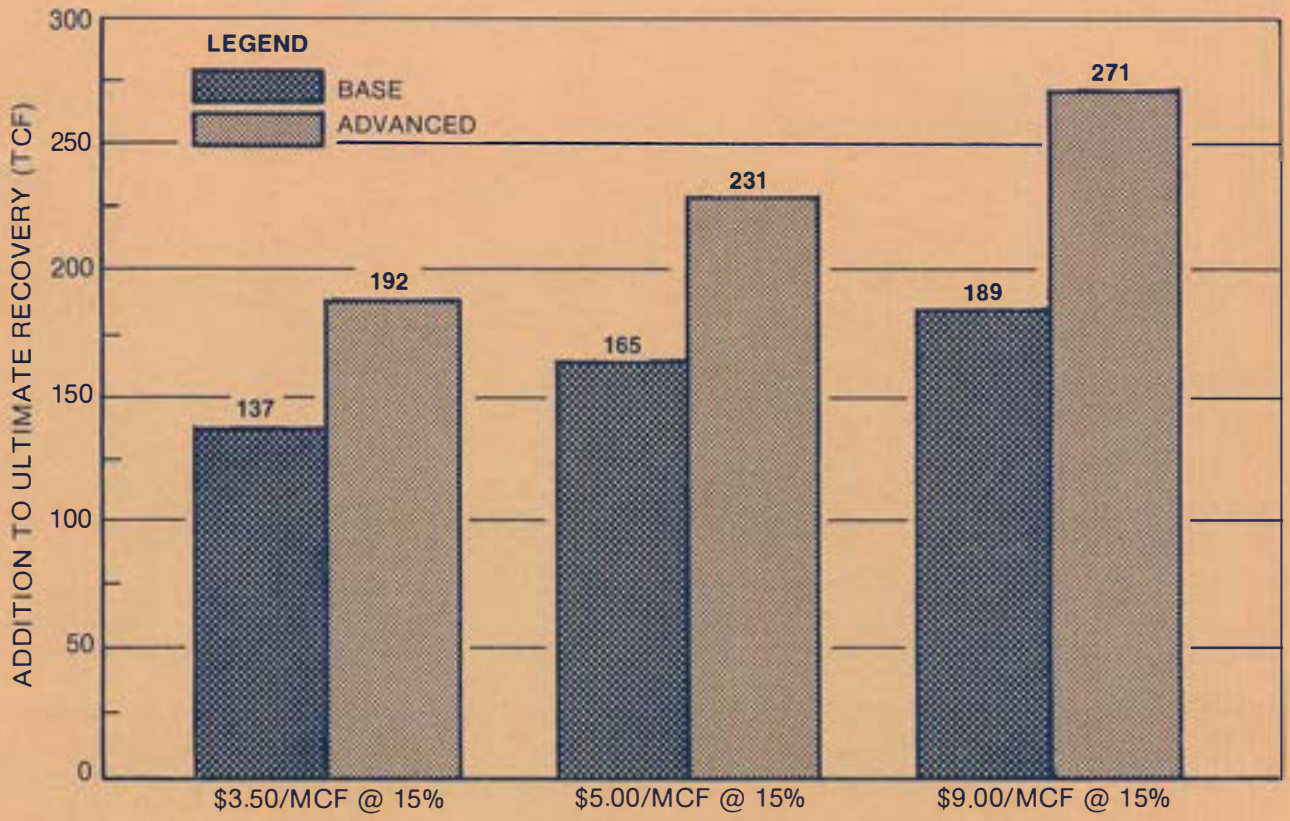


Figure 31. Rocky Mountain, Northern Great Plains/Williston, Southwest Basins.

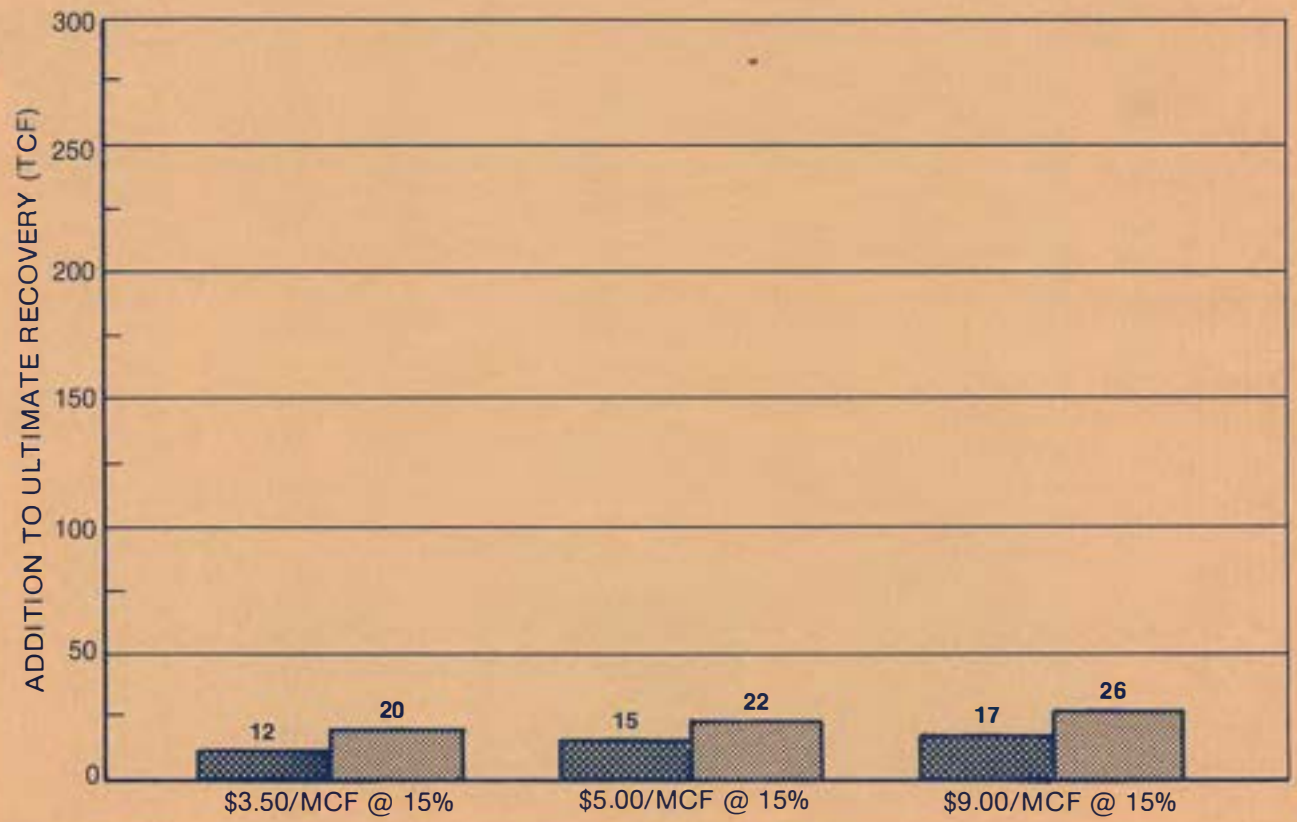


Figure 32. Southwest Basins.

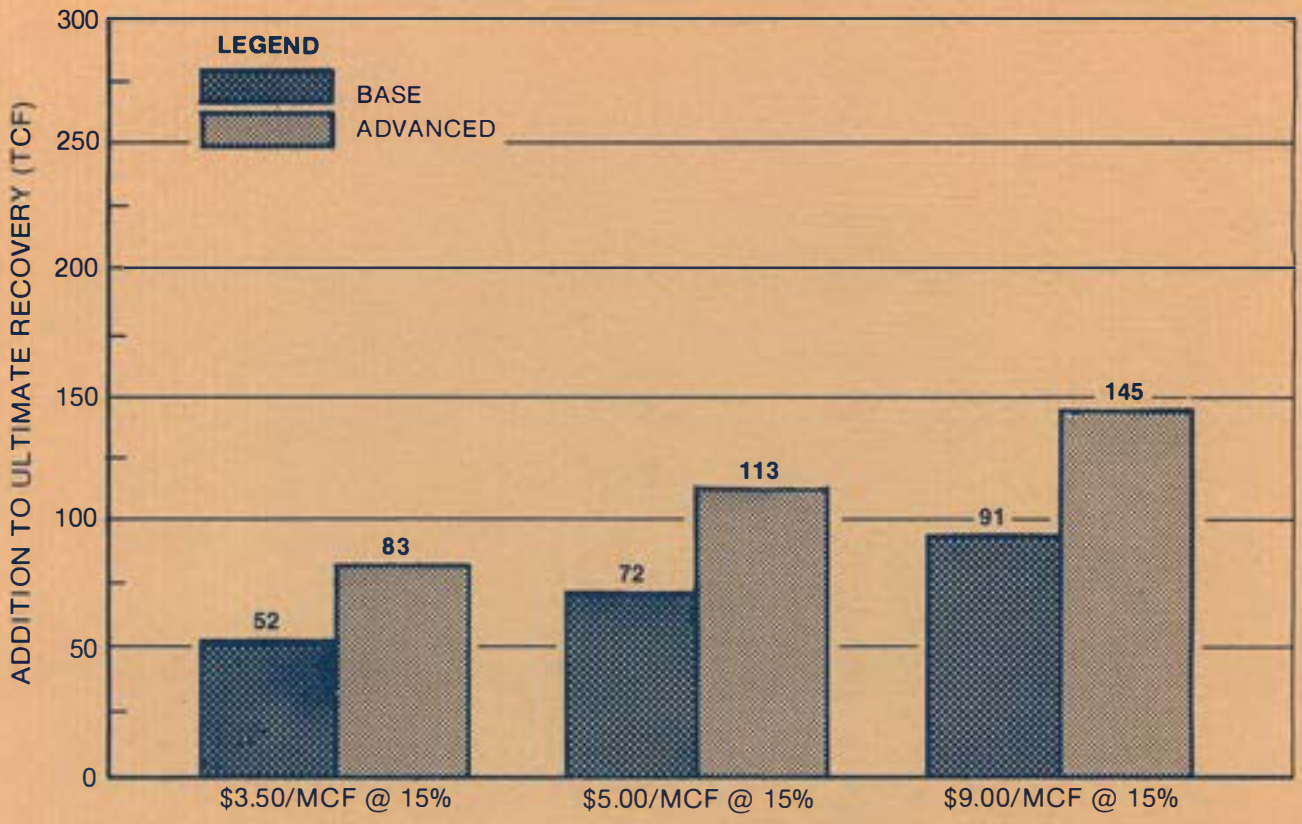


Figure 33. Rocky Mountain Basins.

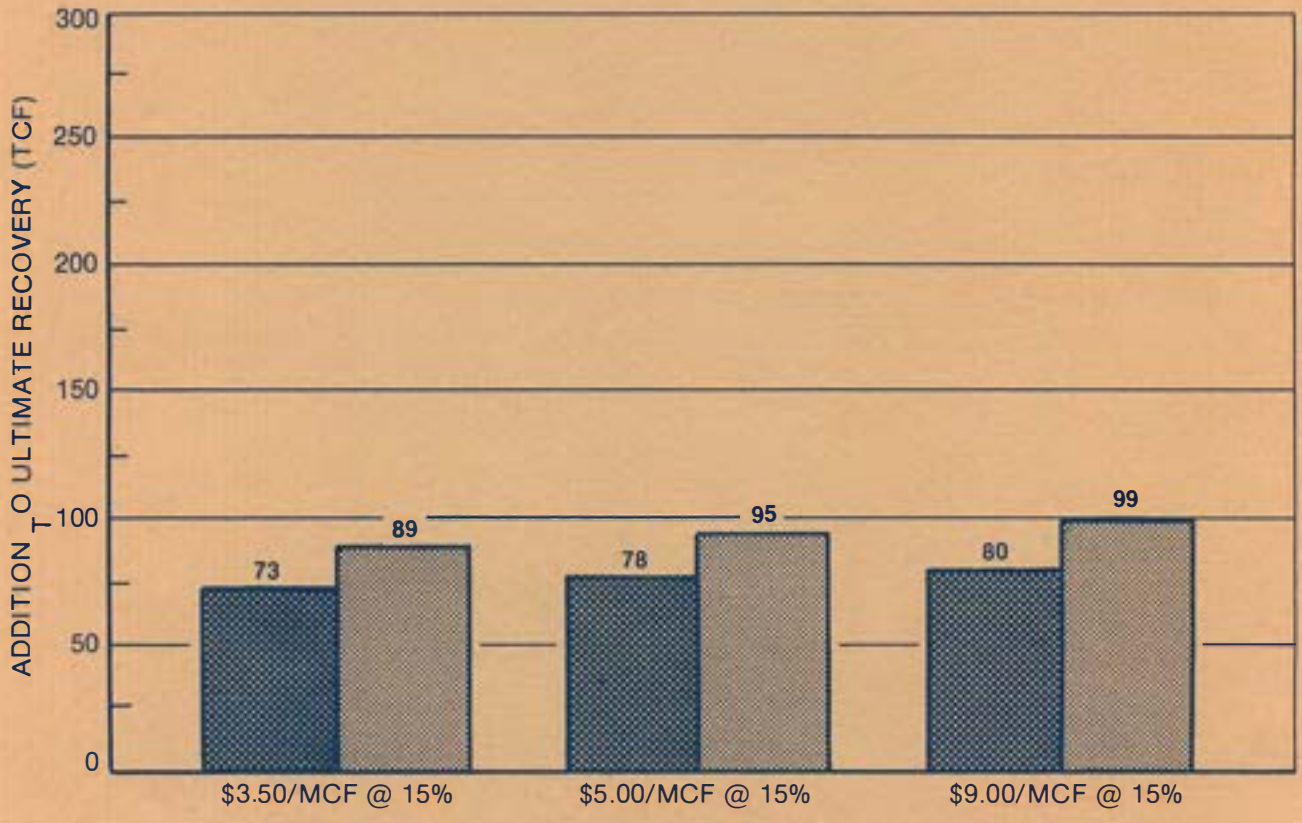


Figure 34. Northern Great Plains/Williston Basins.

TABLE 71

Effects of Price, Technology, and Discount Rate on
Recoverable Gas in the Appraised Basins

	Ultimate Gas Reserve (BCF)	Ultimate Investment (MM $)	$/MCF	Ultimate Gas Reserve (BCF)	Ultimate Investment (MM $)	$/MCF	Δ BCF	Δ $ / BCF Col.1	Δ $ (MM $)	Δ $ / $ Col.2	Δ $ / ΔMCF
	$3.50 @ 15 percent			$5.00 @ 15 percent			Incremental				
Rocky Mountains											
Base	51,936	30,076.7	0.579	74,350	51,943.0	0.699	22,414	0.43	21,866	0.73	0.975
Advanced	83,048	52,404.3	0.631	115,699	91,068.4	0.787	32,651	0.39	38,664	0.74	1.184
Northern Great Plains/Williston											
Base	72,861	24,087	0.331	76,945	27,769	0.361	4,084	0.056	3,682	0.153	0.902
Advanced	89,203	32,682	0.366	95,347	37,085	0.389	6,144	0.069	4,403	0.135	0.717
Southwest											
Base	11,968	5,945.6	0.497	15,431	8,220.4	0.533	3,463	0.289	2,275	0.383	0.657
Advanced	19,698	7,728.9	0.392	22,421	10,529.0	0.470	2,723	0.138	2,800	0.362	1.028
	$5.00 @ 15 percent Advanced			$5.00 @ 10 percent Advanced			Incremental				
Rocky Mountains	115,699	91,068	0.787	126,239	105,685	0.837	10,540	0.09	14,617	0.16	1.387
Northern Great Plains/Williston	95,347	37,085	0.389	96,823	39,104	0.404	1,476	0.015	2,019	0.054	1.368
Southwest	22,421	10,529	0.470	25,448	14,178.5	0.557	3,027	0.135	3,649.5	0.347	1.206

TABLE 72

Effects of Price, Technology, and Discount Rate on
Recoverable Gas in the Appraised Basins

	Ultimate Gas Reserve (BCF)	Ultimate Investment (MM $)	$/MCF	Ultimate Gas Reserve (BCF)	Ultimate Investment (MM $)	$/MCF	ΔBCF	ΔBCF / BCF Col.1	Δ$ (MM $)	Δ$ / $ Col.2	Δ$ / ΔMCF
	$5.00 @ 15 percent			$9.00 @ 15 percent			Incremental				
Rocky Mountains											
Base	74,350	51,943	0.699	94,371	80,363	0.852	20,021	0.27	28,420	0.55	1.419
Advanced	115,699	91,068	0.787	150,182	153,012	1.019	34,483	0.30	61,944	0.68	1.776
Northern Great Plains/Williston											
Base	76,945	27,769	0.361	78,958	30,613	0.388	2,013	0.026	2,844	0.102	1.413
Advanced	95,347	37,085	0.389	99,372	42,003	0.423	4,025	0.042	4,918	0.133	1.222
Southwest											
Base	15,431	8,220.4	0.533	16,722	10,039.3	0.600	1,291	0.084	1,819	0.221	1.409
Advanced	22,421	10,529	0.470	26,135	15,449.4	0.591	3,714	0.166	4,920	0.467	1.325
	$5.00 @ 20 percent Advanced			$5.00 @ 15 percent Advanced			Incremental				
Rocky Mountains	97,699	67,288	0.689	115,699	91,068	0.787	18,000	0.18	23,780	0.353	1.331
Northern Great Plains/Williston	91,188	34,272	0.376	95,347	37,085	0.389	4,159	0.046	2,813	0.082	0.676
Southwest	22,290	10,144.7	0.455	22,421	10,529	0.470	131	0.006	384	0.038	2.93

TABLE 73

Effects of Price, Technology, and Discount Rate on
Recoverable Gas in the Appraised Basins

	Base			Advanced			Incremental				
	Ultimate Gas Reserve (BCF)	Ultimate Investment (MM $)	$/MCF	Ultimate Gas Reserve (BCF)	Ultimate Investment MM $	$/MCF	Δ BCF	Δ BCF / BCF Col.1	Δ $ (MM $)	Δ $ / $ Col.2	Δ $ / Δ MCF
Rocky Mountains											
$3.50 @ 15 percent	51,936	30,076.7	0.579	83,048	52,404.3	0.631	31,112	0.60	22,327.6	0.74	0.72
$5.00 @ 15 percent	74,350	51,943.0	0.699	115,699	91,068.4	0.787	41,349	0.56	39,124.4	0.75	0.95
$9.00 @ 15 percent	94,371	80,363.0	0.852	150,182	153,012.0	1.019	55,811	0.59	7,264.9	0.90	1.30
Northern Great Plains/Williston											
$3.50 @ 15 percent	72,861	24,087.3	0.331	89,203	32,681.9	0.366	16,342	0.224	8,594.6	0.357	0.526
$5.00 @ 15 percent	76,945	27,769.5	0.361	95,347	37,084.9	0.389	18,402	0.239	9,315.4	0.335	0.506
$9.00 @ 15 percent	78,958	30,613.5	0.388	99,372	42,003.2	0.423	20,414	0.259	11,389.7	0.372	0.558
Southwest											
$3.50 @ 15 percent	11,968	5,945.6	0.497	19,698	7,728.9	0.392	7,730	0.646	1,783.3	0.300	0.231
$5.00 @ 15 percent	15,431	8,220.4	0.533	22,421	10,529.0	0.470	6,990	0.453	2,308.6	0.281	0.330
$9.00 @ 15 percent	16,722	10,039.3	0.600	26,135	15,449.4	0.591	9,413	0.563	5,410.1	0.539	0.575

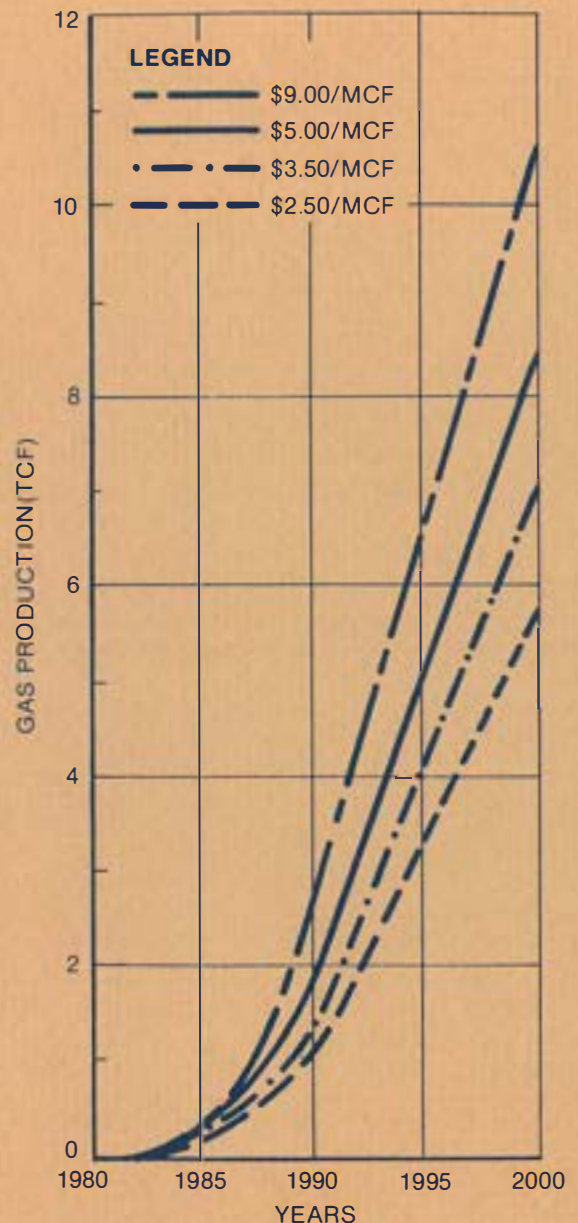


Figure 35. Annual Tight Gas Production for 15 Percent Discount at $2.50, $3.50, $5.00, and $9.00/MCF.

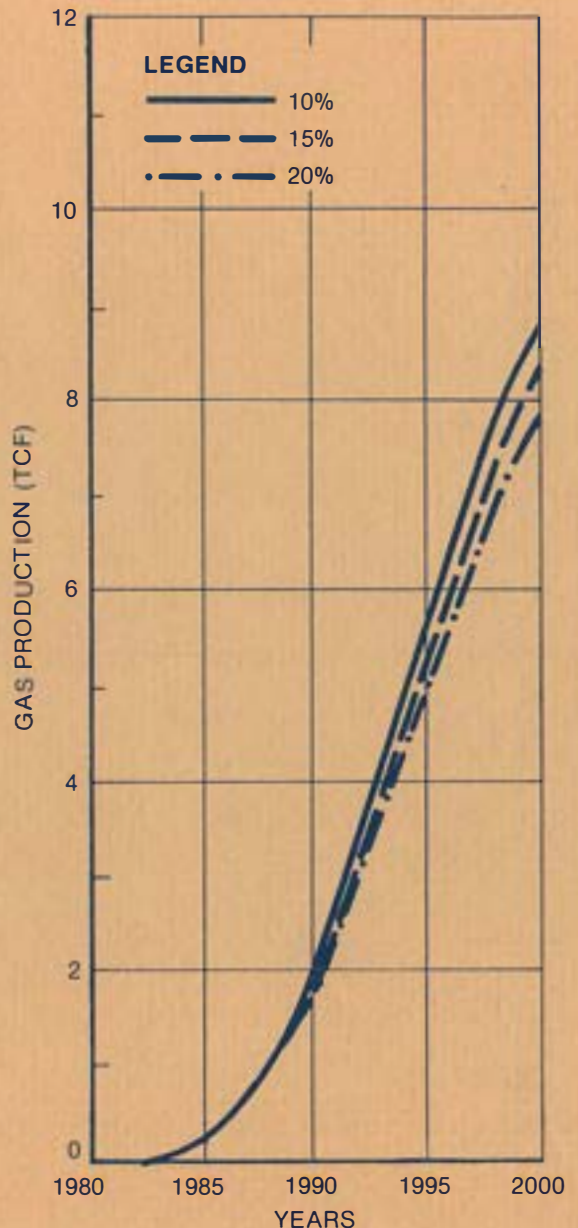


Figure 36. Annual Tight Gas Production at $5.00/MCF for Various Discount Rates of 10, 15, and 20 Percent.

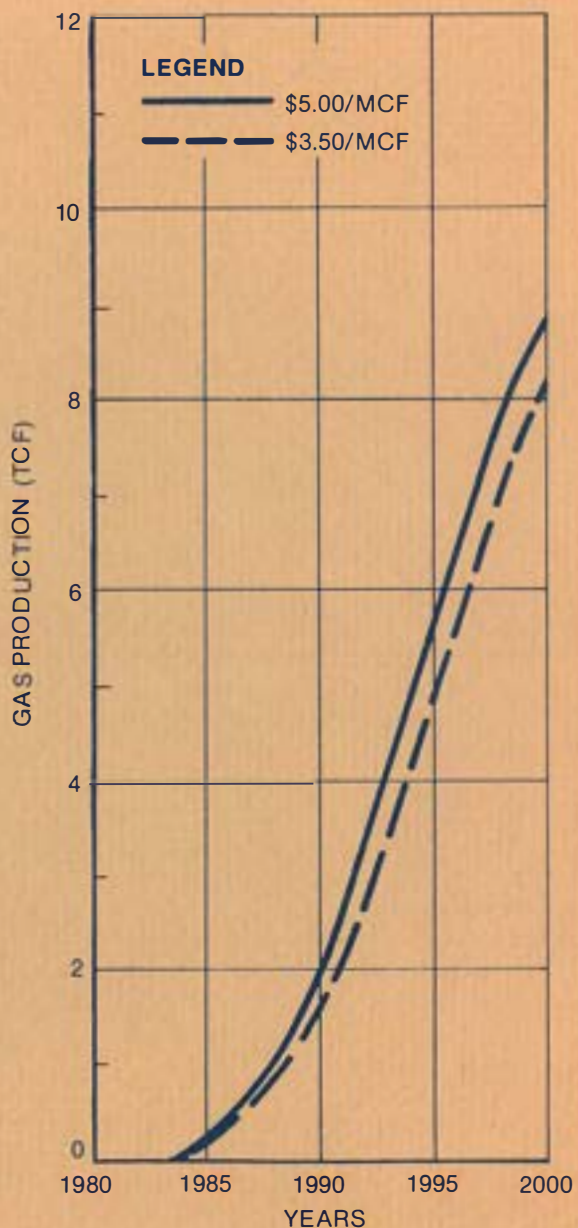


Figure 37. Annual Tight Gas Production for 10 Percent Discount Rate at $3.50 and $5.00/MCF.

Williston. It is the base case only at $5.00 and a 15 percent marginal rate. Approximately the same number of prospects are developed as in the standard scenario. The approximation is necessary because in some instances the base case was not profitable at $5.00.

This procedure permits a comparison of base case only with a reasonable schedule of improvement by advanced case technology. This comparison is discussed in Chapter Eight in the section entitled "Benefits, Research Cost, and Research Timing Required to Achieve Advanced Technology."

A set of scenarios for this study will be found in Appendix E. These tables contain abundant detail on drilling schedules, reserves added, annual and cumulative production, investment and annual cash flow, as well as typical profitability indicators such as rate of return, profit per investment, and net present value. Scenarios covered in Appendix E include:

Standard Scenario at $5.00 and 15 Percent,
Base and Advanced Technology

Standard Scenario at $3.50 and 15 Percent,
Base and Advanced Technology

Recompletion of Old Wells in Tight Gas Reservoirs
Half-Standard Scenario, Southwest Region at $5.00
and 15 Percent, Base Technology

Range of Production Rates Projected

Any potential recoverable reserve is associated with a price for the gas. The amount of tight gas produced per year depends on market demand, which will determine the price. The EIA has projected gas demand but there are possibilities of a higher demand. One of these is the replacement of imported oil. If U.S. imports were reduced drastically by some of the producing countries, a rapid increase in gas production would be desirable.

The production rates for the standard, half-standard, and twice-standard scenarios are displayed in Figure 30 for the 1981-2000 period. All of these scenarios are for a price of $5.00/MCF. These three scenarios represent a large range of production schedules. The twice-standard scenario would produce more gas than the market could be expected to use. The half-standard scenario is more like the EIA projection for tight gas. The three scenarios do not include tight gas now being produced from proven reserves. The EIA projection does include production from current proven reserves. An estimate of the EIA projection of production from reserves discovered in the 1981-2000 period is also displayed in Figure 30.

The EIA estimate shows higher production rates at an earlier date than the NPC scenarios. The EIA estimate seems to track the

Lewin and Associates estimate for base case technology for their 13 basins.[2] The Lewin economics are based on production starting one year after the well drilling investment is made.[3] EIA's estimate includes tight gas produced from reserves discovered before 1980.

The NPC economics were based on the following schedule:

Year	Action
1	Geologists explore and select a prospect and wildcat location.
2	Drill first wildcat.
3	Drill second wildcat if first one is dry. If first wildcat is successful and profitable drill some development wells.
4	Pipeline connection to the new field is made and production begins.
5	Drill additional development wells at such a rate that the delivery pipeline from the field is flowing gas at nearly a constant rate for many years. Since tight gas wells decline in production rapidly, it is necessary to keep drilling new ones. The development drilling schedule can extend until the 15th year.

This scheduled delay is based on experience with new field wildcats.

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[2]Lewin and Associates, Enhanced Recovery of Unconventional Gas, Vol. II, Febuary 1978, pp. 3-11, Exhibit 3-2, at $4.50/MCF price (same as $5.45/MCF in January 1, 1979, dollars).

[3]Lewin and Associates, Enhanced Recovery of Unconventional Gas, Vol. III, pp. 3-126.

Chapter Six

CONSTRAINTS TO THE DEVELOPMENT OF TIGHT GAS RESOURCES

INTRODUCTION

There are several potential constraints to the development of the tight gas resource.

- Market demand at the prices necessary to produce the gas may not be available.
- More operators will have to become convinced that the production technology is dependable, the gas resources are available, and the economics are favorable before many tight gas plays are begun.
- Pipeline capacity may have to be expanded in many parts of the country.
- The supply of materials, manpower, and services may be limited.
- The investment requirements will be significant.
- Withdrawal of federal lands from energy and other uses could reduce the potential gas resources available.
- Environmental concerns could pose constraints.
- Gas price regulations could pose constraints.

These potential constraints have been considered and their relationship to the three scenarios examined. For advice on these topics, the study participants depended largely on earlier studies by the NPC and on consultation with experts in the subjects involved.

Market Demand

Market demand was estimated by the EIA in Table 3. Their estimate is about equal to the half-standard scenario case. The possibility of using some of the excess gas to replace oil imports is discussed in Chapter Five. It may be feasible to replace most of the oil imports or at least to introduce price competition and moderate world oil prices. Consumers now using oil would have to install gas burners in many cases. To do so they would need to feel confident of a reliable gas supply for several years. Figure 27 projects large supplies of tight gas for about 40 years at a $5.00/MCF price. Market demand will be a constraint, especially after the price of new gas supplies is deregulated in 1985. The resource is adequate to furnish all of the likely demand.

Confidence in Tight Gas Technology Resources and Economies

The Society of Petroleum Engineers and DOE are jointly making a strong effort to organize symposia on fracturing and tight gas technology. These meetings have been attracting a large audience. The Department of Energy research and development program has involved many engineers and advisors from industry. Their joint project with industry on tight gas wells and research projects has increased the confidence of many people in tight gas. The Gas Research Institute is also focusing a major effort in the tight gas area.

The Potential Gas Agency discussion of tight gas in the biannual report of the Potential Gas Committee and the data on tight gas formations submitted by operators to state regulatory agencies as part of the FERC incentive price program will define this gas resource more accurately. The three estimates of tight gas resources made by the Federal Power Commission (1973), Lewin and Associates (1978), and the NPC should reinforce the interest of industry geologists in evaluating their leases for tight gas potential.

The action of the FERC in setting incentive prices for tight gas until 1985 should at least encourage the recompletion of old wells in tight gas formations. The economic analysis of 82 subbasins in the 12 basins should provide some economic guidelines for operators evaluating potential prospects in their area of operation. Pipeline planners may consider the potential in the Rocky Mountain and Montana areas as a major future gas province and a source of gas as their Southeast region gas supplies decline.

These factors will probably have a cumulative effect on the building of confidence in the exploration and production management of the industry.

Pipeline Constraints

This report projects the development of a gas supply region in the Rocky Mountains and Montana that will rival the 1950's development of the southwest as a gas province. Since this development is only beginning, the major pipeline capacity required is not yet built. It is anticipated that this constraint will be removed in an orderly manner during the 1982-2000 period.

Present Regional Pipeline Capacity

At present, only four states are net exporters of gas; all of these are in the southwest (Table 74). As the United States moves to higher prices for gas, almost every state becomes a potential producer of tight gas.

There are many gas transfer pipelines within the Southwest region, but the 1979 NPC study Storage and Transportation Capacities indicates the net 12 TCF per year export capacity shown in Table 74. Estimated excess capacity is shown in Table 75 for new pipelines to the Rocky Mountains and Montana-Dakota expected to be in operation before 1985.

TABLE 74

Southwest Regional Export
Pipeline Capacity

From	To	Maximum Capacity MMCF/D	TCF/Yr
New Mexico	Arizona	4,375	1.597
Oklahoma	Kansas	6,318	2.306
Texas	Arkansas	1,950	0.712
Louisiana	Arkansas	7,836	2.860
Louisiana	Mississippi	12,428	4.536
Total		32,907	12.011

TABLE 75

Probable Excess Pipline Export Capacity
(TCF/Yr)

	1980	1982	1984
Montana-Dakota	0	0.11	0.11
Rocky Mountains	0.106	0.179	0.288

The pipelines will carry mostly conventional gas, but the excess capacities shown should be available for tight gas.

Rate of Building New Pipelines to Deliver Gas Produced

The rate of building new pipelines to adjust for expanded gas production was estimated for the standard scenario as shown in Tables 76 and 77. These data are combined with the following estimates of gas available for export in each region to determine pipeline capacity need in the 1985-2000 period.

Table 78 indicates that major new pipeline systems will be needed in the western states. Some five new gas pipelines are expected to be built to the western states by 1984. A total of eight additional pipelines will be needed to market the tight gas production during the 1985-2000 period.

Pipeline planners for gas transmission companies believe the schedule of pipeline construction indicated above is reasonable and feasible. As the gas supply declines and the market price rises toward world energy prices, the tempo of exploration and development of tight gas will increase sharply.

Constraints to the Supply of Materials and Manpower

It was considered necessary to determine whether the availability of materials and manpower would present a constraint to the

TABLE 76

Rate of Building New Pipelines to Deliver Gas Produced

Year	Gas Produced Inside Region (TCF/Yr) Conventional	Tight Standard Scenario	Total	Gas Used Inside Region (TCF/Yr)	Net Gas for Export (TCF/Yr)	Total Pipeline Capacity (TCF/Yr)	New Pipeline Capacity Needed (TCF/Yr)	Number of New Pipelines with 1,000 MMCF/D Capacity
				Southwest Region				
1978	17.19*	--	17.19	7.86	9.33	12.011	--	--
1980	15.9	--	15.9	7.86	8.04	12.011	0	0
1985	13.1	0.02	13.12	7.86	5.25	12.011	0	0
1990	11.2	0.46	11.66	7.86	3.80	12.011	0	0
1995	9.2	2.16	11.36	7.86	3.50	12.011	0	0
2000	7.2	4.13	11.33	7.86	3.47	12.011	0	0

*U.S. government statistics were declined at an estimated total incremental decline for all United States.

TABLE 77

Rate of Building New Pipelines to Deliver Gas Produced

Year	Gas Produced Inside Region (TCF/Yr) Conventional	Tight Standard Scenario	Total	Gas Used Inside Region (TCF/Yr)	Net Gas for Export (TCF/Yr)	Excess Pipeline Capacity (TCF/Yr)	New Pipeline Capacity Needed (TCF/Yr)	Number of New Pipelines with 1,000 MMCF/D Capacity
				Montana-Dakota				
1985	0.08	0	0.08	0.15	-0.07	0.11	0	0
1990	0.08	0.13	0.21	0.15	0.06	0.11	0	0
1995	0.08	0.44	0.52	0.15	0.37	0.11	0.26	1
2000	0.08	0.78	0.86	0.15	0.71	0.11	0.6	2
				Rockies				
1985	0.60	0.08	0.68	0.48	0.20	0.29	0	0
1990	0.87	0.6	1.47	0.48	0.99	0.29	0.7	2
1995	0.90	1.2	2.10	0.48	1.62	0.29	1.33	4
2000	0.94	1.8	2.74	0.48	2.26	0.29	1.97	6

TABLE 78

Schedule of New 42", 1 BCF/Day Pipelines Needed After 1984
for Tight Gas Production

Year New Pipeline Begins Operations	Northern Great Plains/ Williston	Rocky Mountains	Southwest	Other U.S.	Total
1985	0	0	0	NA	0
1990	0	2	0	NA	2
1995	1	2	0	NA	3
2000	1	2	0	NA	3
Total	2	6	0	NA	8

development of U.S. tight gas resources. The National Petroleum Council carried out a study and issued a report in 1979 entitled Materials and Manpower Requirements for U.S. Oil and Gas Exploration and Production -- 1979-1990, and it was felt that this study would provide an adequate up-to-date evaluation. The basis for much of this earlier NPC report was established by means of surveys of manufacturers and source suppliers. In general, the reaction was that the industry could expand the market, and on this basis it is believed that it can extend beyond 1990. The following sections provide the essential information quoted from that report.

Conclusions

The availability of equipment, materials, and services is unlikely to be a constraint to future industry activity levels. In addition, the manpower required will be adequate to support substantial increases in activity. However, any changes in laws and regulations which improve the business environment will also directly increase activity.

The manufacturing, supply, and service industries currently have spare capacity, which, together with expansion plans, should be adequate through 1981. In the longer term, the capability to add capacity where needed is sufficient to supply a substantial growth in demand.

The discovery and subsequent development of any major foreign frontier areas should not pose constraints to domestic activity levels.

Although the 1979 NPC study indicated that there would be sufficient capacity to support an important and necessary increase in activity, the study did identify a number of areas where capacity

would be tight and where constraints could develop, especially with a substantial increase in activity. The most significant concerns appear to be in the general area of iron and steel.

- Oil country tubular goods (oil well casing, tubing, and drill pipe) would fall short of demand by 1985 with a substantial increase in activity, and by 1990 with a lesser increase. Worldwide capacity should allow the shifting of these patterns to meet domestic needs. However, this would result in the increasing reliance on potentially insecure foreign sources.

- There is some concern about the adequate future availability of castings and forgings. A significant factor is the loss of capacity which has resulted from the shutdown of many small foundries unable economically to meet EPA and OSHA requirements.

- Most industry segments expressed concern over a potential future shortage of raw steel.

Recommendations

Based on the findings and conclusions set forth in the report, the National Petroleum Council recommended the following measures to improve and expand the exploration, drilling, and production capabilities:

- The federal government should continue to promote the development of domestic energy resources and strive to establish a stable and predictable business climate. The creation of such an environment will entail the review of federal laws and regulations relating to leasing, price controls, taxation, and environmental preservation.

- The federal government should create an environment which promotes the reestablishment of a strong and competitive domestic steel industry. This environment should encourage the expansion of domestic pipe mill capacity and will require the review of laws and regulations on steel imports, environmental controls, and taxation.

Approach to the Study

A 1974 National Petroleum Council report entitled Availability of Materials, Manpower, and Equipment for the Exploration, Drilling and Production of Oil -- 1974-1976 focused almost entirely on the years 1974-1976. The approach utilized in that study was to establish an industry activity level by assuming that all available drilling rigs would be employed to their maximum capacity. Other industry segments were then tested for potential constraints at that activity level. For the current study, the Department of Energy indicated that the methodology used in the 1974 study would be acceptable, but asked that sensitivity analyses be done for activity levels other than those derived through that methodology.

The NPC therefore formulated an approach intended to minimize the difficulty in reaching broad agreement on a single projection and one which would potentially provide useful information to those using the results of the study. The approach employed was to segment the issue into two separate and somewhat independent areas of investigation:

- The projected capability of the manufacturing supply and service industries to support the petroleum industry
- A projected range of possible industry drilling activity based on published and private forecasts.

These two projections were then compared to determine the extent to which industry activity levels might be constrained by the possible lack of availability of materials or manpower.

Concurrent with this effort, an examination was conducted of the impact of federal laws and regulations.

Surveys were used extensively to obtain data which would assist in analyzing the capacities of the individual segments of the manufacturing, supply, and service industries. The survey approach was also used as an aid in identifying the impact of government regulations and the future business environment on activity levels.

Drilling Activity Outlook. An analysis of 23 independent forecasts of U.S. drilling activities by various service and supply, industry, government, and financial institutions formed the basis for projection of a range of possible drilling activity. The upper level of the possible activity range reflects a 6 percent average annual growth in wells drilled from 1979 through 1981 and 3 percent annual growth from 1982 through 1990. The lower level of the activity range assumed growth and drilling of almost 2 percent per year for 1979 through 1981 and just over 2 percent per year for 1982 through 1990.

During 1979, actual drilling activity was below the lower level of the projected activity range. This was due largely to the delay and uncertainty of improvements in producer profitability expectations. Improving profitability expectations are expected to bring drilling into the projected possible activity range. However, continued significant improvement in exploration and production investment incentives will be required to achieve the upper level of the projected activity range.

An extension of these projections was used in the Table 79 comparison of the demand for tight gas drilling. The percentage of U.S. drilling effort devoted to gas has been going through a typical growth wave since the late 1940's. Figure 38 has been used to estimate the total number of gas wells drilled in the United States until the year 2000.

For each of the three scenarios the number of tight gas wells committed annually is shown. These will be spaced over a three- to

TABLE 79

Drilling Projections

Year	Estimated Total U.S. Oil and Gas Wells Drilled Annually*	Estimated Gas Wells Drilled Annually		Estimated Tight Gas Wells Committed for Drilling Annually For Scenarios				Standard Scenario (Percentage of U.S. Gas Supply From Tight Gas)
		Total Wells	Exploration Wells	Half-Standard Wells	Standard % of Gas Wells	Standard Wells	Twice-Standard Wells	
1980	55,300	27,100	8,700	--	--	--	--	--
1985	64,600	34,900	9,400	2,449	14	4,900	5,577	1
1990	70,800	41,800	10,000	4,642	22	9,403	18,540	9
1995	82,100	50,900	12,500	4,153	17	8,400	21,241	22
2000	95,100	60,400	15,100	4,319	13	7,925	18,626	33

*NPC Materials and Manpower Requirements for U.S. Oil and Gas Exploration and Production, 1979 -- 1990, p. 14. All well numbers include dry wells as well as successful ones.

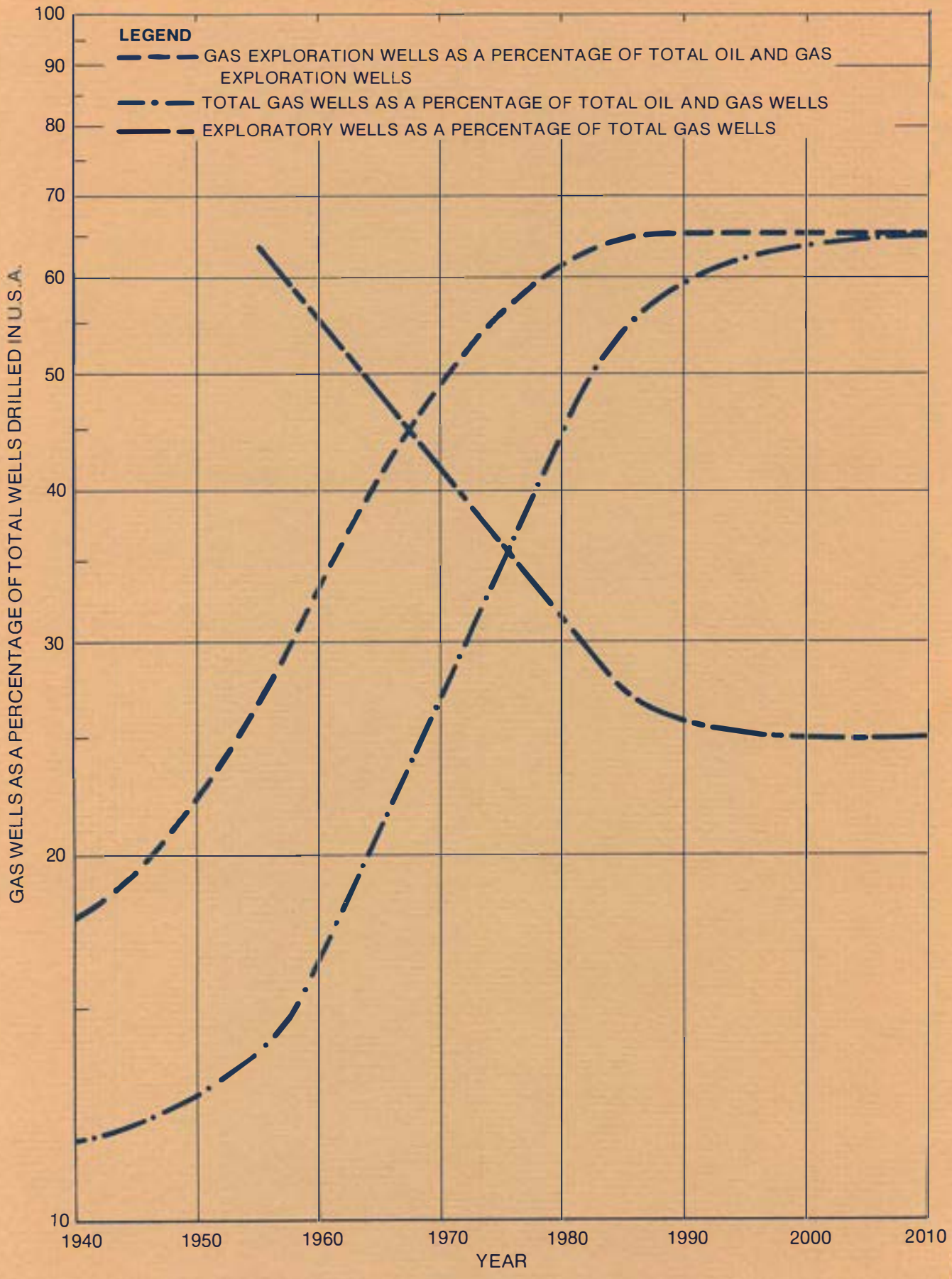


Figure 38. Gas Wells Drilled.

10-year period, but they are wells resulting from the number of prospects started in each year. The proportion of gas wells drilled for tight gas in the standard scenario ranges from 13 to 22 percent of the total number of gas wells drilled. The percentage of the total U.S. gas supply projected for tight gas in the standard scenario range from 9 to 33 percent in the period 1990-2000, as shown in Table 79. The number of tight gas wells seems reasonable compared to the total number of all gas wells projected.

Geological and Geophysical Services. Geological services is a manpower-intensive professional service for which few materials are required.

The non-Communist world geophysical services industry is largely U.S. based. A consistent domestic market is a key factor assuring consistent availability of domestic capacity. U.S. geophysical activity accelerated to a growth rate of 21 percent in 1977 and 1978; with projected capacity this growth rate is sustainable through 1981. Geophysical services are not expected to limit drilling activities. However, possible future shortages in vibratory sources and recording instruments are identified as potential but not probable constraints.

Wireline service demand (logging and perforating) is directly related to drilling activity. This industry has grown at a compound rate of about 10 percent in logging and perforating field units since 1970, and projected capability will sustain this growth through 1990. This is a substantially higher rate than the upper level of possible drilling activity.

Drilling Equipment. The drilling equipment industry has the present capability and is expected to have continued capacity in the future to support domestic drilling along the upper range of possible activity levels. Projections of basic rig manufacturing capacity (dedicated to the U.S. market) exceed total projected upper level possible demands to the year 1990. A capability to further increase capacity by 25 percent in less than a year and to double capacity in about two years was indicated.

Adequate capacity is projected through 1981 for major auxiliary equipment, including the drilling string (drill pipe, tool joints, drill collars, and bits) and pressure control equipment (blowout preventers and control systems).

Drill pipe mill capacity is projected to be adequate to meet the upper level drilling activity through 1981, but a potential shortfall is indicated in 1985 and 1990 if exports continue at the historical rate of 40 percent.

The supply of drilling fluid additives is a potential constraint to accelerated drilling activity. However, the industry projects capacity sufficient for upper level drilling to the year 1990.

Tubular Steel. Adequate supplies of oil country tubular goods are expected to be available through 1981. However, the projected upper level demand will be so close to the projected supply by 1981 that a significant user inventory buildup, a drop in import levels, and/or a large increase in exports could result in a tenuous supply/demand balance. Beyond 1981, upper level projected demand would exceed the projected supply by 100,000 tons in 1985 and by one million tons in 1990. The projected shortage might be remedied by one or more alternatives, including increased imports, decreased exports, construction of new tubular mills, shifting of raw steel from other products, or expansion of raw steel supplies as well as additions of tubular mill and finishing capacity.

The most secure and reliable supply of oil country tubular goods would result from the expansion of domestic steel and production capacity. In order for such expansion to occur, the steel industry will need clear, predictable incentives.

Production Equipment. The capacity for manufacturing oil and gas production equipment is expected to be sufficient to support the upper level of possible domestic drilling activity. Key potential constraints include the potential shortages of alloys containing chromium and cobalt, long lead times for machine tools, and shortages of the energy needed for equipment manufacture.

Well Servicing. Well servicing rigs, cementing and stimulation services, specialty tools and services, and air and marine transportation are provided by the well servicing industry. Present capacity plus planned additions will be sufficient to support the projected upper level drilling activity and the production maintenance demands of a growing number of active oil and gas wells.

The available count of well servicing rigs is estimated to increase by a range of 6 to 8 percent per year in 1981 and 4 to 5 percent thereafter to 1990. This nearly equals the projected upper level drilling activity.

Cementing and stimulation service capacity is very sensitive to demand and can respond rapidly. The current shortage of rail cars is a potential constraint which could cause spot shortages of the cement and sand used in large quantities by these services.

The production of specialty tools and services has expanded by nine to 12 percent per year in recent years and is projected to continue growing at a high rate to meet demand.

Land and marine transportation vehicles and vessels are currently in surplus.

Manpower. Exploration and production companies responding to surveys expect that the availability of professional personnel will have a growing impact on the ability to expand rapidly during the 1980-1985 period. Less than half expect the impact to be large. The demand for professionals will be met by rapidly increased enrollment in the critical disciplines geology and petroleum engineering. No circumstances can be foreseen that could produce a

manpower constraint to the expansion of drilling and well servicing activities. The greatest need is for federal policies to relieve uncertainties in the future and thus stabilize demand.

The availability of skilled workers is a recurring concern for all industry sectors, but it is being managed through intensive recruiting and training programs by industry.

Investment Requirements and Capital Availability

The capital requirements of the three scenarios are listed along with the estimated capital available in Table 80.

Economists at Chase Manhattan Bank and Bankers Trust were consulted for their estimates of the capital that could be available to meet industry needs in the United States for exploration and production. That part of the capital requirements allotted for gas was estimated from historical percentages of wells drilled for gas and projected into the 1980-2000 period. Figure 38 shows the projection.

The capital required by the tight gas scenarios does not appear to be too large a portion of the gas capital available. The percentage of the U.S. gas supply furnished by tight gas increases by about 10 percent every five years after 1985 for the standard scenario. The capital needed for conventional gas development is decreasing at the same time. Payout periods are in the range of five to 11 years for the various regions, with an overall U.S. payout of nine years. The maximum unrecovered investment for the United States is estimated to be $670 million and occurs in the sixth year.

The conclusion is that the availability of investment capital will not pose a constraint to the development of the quantities of tight gas shown in these three scenarios.

Withdrawal of Federal Land and Resources From Tight Gas Development

Introduction

In recent years, there has been an increasing effort to set aside federally owned lands for wilderness preservation and environmental protection. Much of this effort originated with the Wilderness Act of 1964 and the Federal Land Policy and Management Act of 1976 (FLPMA). There is some concern that an increase in federal lands set aside for these purposes would prevent the development of a significant amount of tight gas resources. This could be particularly serious in several western states where there is a high proportion of federally owned land and a concentration of tight gas resources.

This report presents the results of a study to determine if federal lands currently withheld from oil and gas development, along with additional federal land which may be withdrawn, will constitute a significant constraint to the development of tight gas

TABLE 80

Investment Capital
(Billions of January 1, 1979, Dollars Per Year)

U.S. Estimated Investment Capital Available for Exploration and Production				Total Gas E&P Investment Capital Estimated This Report	Tight Gas E&P Investment Committed By Each Year's Projects Scenarios*			Standard Scenario (Percentage of U.S. Gas Supply From Tight Gas)
Year	Chase	Bankers Trust	This Report Estimated for Oil and Gas		Half-Standard	Standard	Twice-Standard	
1980	23.3	26.4	24.9	12.5	--	--	--	--
1981	26.1	32.2	29.2	14.6	0.4	1.0	1.2	--
1985	41.7	39.7	40.7	20.4	1.6	3.2	3.8	1
1990	70.8	47.1	59.0	24.0	3.8	7.6	14.7	9
1995	--	--	75.0	48.0	4.1	8.3	18.6	22
2000	--	--	85.0	54.0	4.3	8.0	16.8	33

*May be spent over a three- to 10-year period, but the capital is committed by the project initiated in the year indicated.

resources. This investigation applies only to the 12 prospective tight gas basins considered in this NPC report on tight gas resources.

The three major sources of current federal land withdrawal include existing wilderness designated by various government agencies, the national parks, and national wildlife refuges and waterfowl protection areas. As a rule, oil and gas operations are not allowed on these federal holdings; leases have not been recommended by the United States Forest Service (USFS) on national forest wildernesses as a general policy in past years. The major sources of potential federal land withdrawal include the wilderness study areas designated by the U.S. Bureau of Land Management (BLM), and the U.S. Forest Service Roadless Area Review and Evaluation II (RARE II) wilderness and further planning areas endorsed by the Administration in April 1979.

In November 1980, the BLM designated various Wilderness Study Areas (WSA) in the United States to be evaluated to determine if it should recommend that some or all of these be set aside for wilderness preservation. The USFS completed its RARE II wilderness studies and the Administration made its recommendations to Congress in 1979. The BLM wilderness studies must be completed by 1991, but most of the studies will probably be completed between 1979 and 1985. As these studies are completed, the BLM will make its wilderness recommendations to Congress, which has final authority in these matters. It should be noted that oil and gas operations in the designated study areas are prohibited or restricted during the study and decision phases of the BLM and USFS wilderness study programs. (See the section entitled "Restrictions on Oil and Gas Development Within Federally Designated Wilderness Study Areas and Wilderness Areas.")

By agency policy, oil and gas operations will probably not be allowed in those areas which Congress sets aside for wilderness preservation. However, in some areas, there will undoubtedly be existing oil and gas leases, and active development may be allowed to continue with specified restrictions. (See "Restrictions on Oil and Gas Development Within Federally Designated Wilderness Study Areas and Wilderness Areas.")

The federal government may own and/or administer land in other ways, such as in the National Recreation Areas, reclamation and water power development projects, oil shale withdrawal lands, and special Indian legislation land. However, as a general rule, oil and gas development is allowed on these lands; this, then, does not constitute withdrawal from resource development. There are a number of Indian reservations in the western states as well, but these are usually open to oil and gas leasing.

It is important to note that oil and gas development can usually be carried out on essentially any federal land if the subsurface mineral rights are owned by private individuals. However, the federal government specifies the conditions under which the development can take place. In the case of BLM and USFS wilderness study

areas, the federal government is usually the owner of the mineral rights. On the other hand, it is not uncommon for private interests to own a portion of subsurface mineral rights in wildlife refuges and waterfowl protection areas. National parks have traditionally been closed to oil and gas development regardless of whether they have been declared wilderness areas. This is also true of wildlife refuges and waterfowl protection areas.

Summary of Findings

Table 81 presents the overall results of this land withdrawal study. It indicates that current and potential withdrawal of federal land and resources from oil and gas development would exclude about 5 percent of the tight gas resources in the basins being considered. This represents the maximum possible withdrawal; the actual would probably be less. One reason for this is that Congress may not set aside all the land recommended for wilderness preservation. Also, some of the tracts recommended for wilderness will already be subject to oil and gas leases and operations, and development will probably be allowed to continue on some of them. Furthermore, environmental impairment due to the development and production of gas resources is generally less severe than in mining operations, and restoration of the environment is usually more easily accomplished. In addition, gas-producing operations last only about 30 years. These facts should motivate the federal agencies involved to permit tight gas development in those wilderness areas with significant gas resources.

Table 81 indicates that the most significant current and potential withdrawal of federal lands from tight gas development would be in the Northern Great Plains/Williston basin. Even here, however, current and potential withdrawal represents only about 9 percent of the tight gas resources. About 69 percent of the land withdrawal is the result of a large existing wildlife refuge which extends along the Missouri River in northeastern Montana. Most of the other potential withdrawal originates with several BLM wilderness study areas. However, there are a number of oil and gas development operations in some of these wilderness study areas, and the BLM may permit further development on some of them. If the current and potential withdrawal of tight gas resources in the Northern Great Plains/Williston basin is combined with comparable resources in the Greater Green River basin, the total will represent about 93 percent of total current and potential withdrawal in all of the tight gas basins considered in this report.

In the Piceance, Wind River, and Uinta basins, current and potential withdrawal of tight gas resources ranges from about 1.0 to 1.5 percent of the tight gas resources in these basins. In the remaining six basins considered, investigations indicate that tight gas reserve development would not be affected by either existing or potential withdrawal of federal lands. These include the San Juan, Cotton Valley, Edwards Lime, Val Verde-Sonora and Ozona, and Denver basins.

TABLE 81

Existing and Potential Federal Land/Resources Withdrawal from Tight Gas Exploration and Development
Selected Tight Gas Basins

		Northern Great Plains/ Williston	Greater Green River	Piceance	Wind Riv.	Uinta	Cotton Valley	Edwards Lime	Denver (Est)	San Juan	Sonora (Est)	Val Verde Ozona (Est)	Total
1.	Existing Wilderness (all US Gov.Agencies) (Incl.under Wildlife Refuges)												
	Sections- (640 acres)	0	0	36	0	0	0	0	0	0	0	0	36
	BCF-	0	0	116	0	0	0	0	0	0	0	0	116
2.	Wilderness Study Areas- (US Bur.Land Mgmt.)												
	Sections-	386	334	43	11	11	0	0	0	0	0	0	785
	BCF-	1302	4007	410	212	133	0	0	0	0	0	0	6064
3.	Rare II Land -Sections-	26	0	0	0	0	0	0	0	0	0	0	26
	(US Forest Service)BCF-	147	0	0	0	0	0	0	0	0	0	0	147
4.	Wildlife Refuges(US Fish & Wildlife Serv.Gov.owned minerals) Sections-	1658	3	0	0	1	0	0	0	0	0	0	1662
	BCF-	7043	15	0	0	13	0	0	0	0	0	0	7071
5.	Waterfowl Prod.Areas(US Fish & Wildlife Serv-Gov. owned minerals) Sections-	2	0	0	0	0	0	0	0	0	0	0	2
	BCF-	3	0	0	0	0	0	0	0	0	0	0	3
6.	National Parks(US Park Serv.) Sections-	2	0	0	0	0	0	0	0	0	0	0	2
	BCF-	4	0	0	0	0	0	0	0	0	0	0	4
	Total Exist. & Potential Withdrawal - Sections-	2074	337	43	47	12	0	0	0	0	0	0	2513
	BCF-	8499	4022	410	328	146	0	0	0	0	0	0	13405
	Total Tight Gas Resources All Form./Areas Sections	32730	8938	3171	2280	1184	1027	450	1600	1188	350	150	53068
	BCF-	100188	81762	32979	23286	15269	12816	8648	7918	2213	2160	638	287877
	Current & Potential Withdrawal as % of Total Tight Gas Res. Sections-	6.3	3.8	1.4	2.0	1.0	0	0	0	0	0	0	4.7
	BCF-	8.5	4.9	1.2	1.4	1.0	0	0	0	0	0	0	4.7

Overall, about 53 percent of the current and potentially withdrawn resources in the tight gas basins originates with existing wildlife refuges and about 45 percent with BLM wilderness study areas. Thus, existing wildernesses, RARE II proposed wildernesses, existing waterfowl protection areas, and national parks constitute 2 percent of the current and potential tight gas resource withdrawal. None of the RARE II lands designated for "further planning" fall within the tight gas prospective areas in the basins.

Estimates of current and potentially withdrawn tight gas resources presented in this report are based on estimates of maximum recoverable tight gas for designated tight gas areas/formations developed in other sections of this NPC study. Estimates of these withdrawn resources were developed by totaling estimated withdrawn resources in designated portions of each basin containing withdrawn or potentially withdrawn federal land. The withdrawn resources estimates for each of these designated productive areas/formations in the basins were made by multiplying the maximum recoverable tight gas in each productive area/formation by the ratio of withdrawn land acreage to the total tight gas productive acreage in the area.

Review of Current and Potential Federal Land/Resources Withdrawal from Tight Gas Development by Individual Tight Gas Basins

- Northern Great Plains/Williston Basin, Montana, and North and South Dakota (See Table 82)

This prospective tight gas basin covers most of the eastern half of Montana and about 20 percent of adjoining North and South Dakota. It contains a very large wildlife refuge (called CM Russell) that extends along either side of the Missouri River for almost 200 miles. It is about 922,000 acres, or 1,440 sections (640 acres per section), in size. The federal government owns most of the mineral rights under this acreage and does not allow oil and gas development on it. This refuge is by far the largest single area of withdrawn land in all the tight gas basins considered in this study. In addition, the federal government owns mineral rights in 16 other wildlife refuges and several waterfowl protection tracts in the tight gas area of the basin. Together, the refuges and waterfowl protection areas account for about 83 percent of the current and potential withdrawal of tight gas resources in the basin. From an overall standpoint, they represent about 7 percent of the total tight gas resources in the basin.

The prospective tight gas area also contains 17 BLM wilderness study areas containing about 1,302 BCF of tight gas resources, or about 15 percent of total current and potentially withdrawn resources in the basin. The area further contains one RARE II proposed wilderness and three national parks.

Overall, the current and potentially withdrawn lands in the basin represent about 8,499 BCF, or about 9 percent of the total tight gas resources in the basin.

TABLE 82

Northern Great Plains - Williston Basin
Existing and Potential Federal Tight Gas Land
and Resources Withdrawal

		Tight Gas Area	Potential Land Withdrawal Sections	Potential Resource Withdrawal (BCF)
1.	Wilderness Study Areas			
356	Bitter Creek	3	92.41	278
677	Musselshell Breaks	4	12.6	
256	Cow Creek (50%)		28.3	
266	Antelope Creek		14.7	
			55.6	217
633	Billy Creek	5	5.4	
657	Seven Blackfoot	"	30.7	
675	Bridge Coulee	"	8.8	
278	Burnt Lodge/Sage Creek	"	23.4	
			68.3	365
702	Buffalo Creek	8	8.8	41
684	Terry Badlands	7	69.6	140
701	Zook Creek	15	13.2	
736	T.R. Breaks Contiguity	"	2.3	
			15.5	65
231	Two Calf Creek	13	13.3	
244	Dog Creek south	"	8.2	
250	Stafford	"	7.3	
253	Ervin Ridge	"	18.8	
256	Cow Creek (50%)	"	28.3	
			75.9	196
	Sub Total - Wilderness Study Areas		386.1	1,302

TABLE 82 (Continued)

Northern Great Plains - Williston Basin
Existing and Potential Federal Tight Gas Land
and Resources Withdrawal

	Tight Gas Area	Potential Land Withdrawal Sections	Potential Resource Withdrawal (BCF)
2. RARE II Land			
1-373 Tongue River Breaks	9	25.9	147
3. Wildlife Refuges			
CM Russell	1	50.4	53
Black Coulee	2	1.0	
Lake Thibadeau	"	.03	
		1.03	2
Creedman Coulee	12	.13	0.1
Hewitt	4	0.9	
U L Bend	"	58.2	
CM Russell		433.6	
		492.7	1,958
Bowdoin	5	23.1	
CM Russell	"	566.2	
		589.3	3,155.3
Lake Mason	16	18.3	27
CM Russell	8	190.2	887
CM Russell	6	133.9	393.7
Medicine Lake	19	45.7	36
DeLacs, N.D.	17	21.4	
Lost Wood, N.D.	"	37.9	
Shell Lake, N.D.	"	0.6	
Lake Ilo, N.D.	"	4.8	
		64.7	357
Lake Zahl, N.D.	7	2.0	4
War Horse	13	3.2	
CM Russell	"	66.3	
		69.5	180
Sub Total - Refuges		1,657.9	7,043

TABLE 82 (Continued)

Northern Great Plains - Williston Basin
Existing and Potential Federal Tight Gas Land
and Resources Withdrawal

	Tight Gas Area	Potential Land Withdrawal Sections	Potential Resources Withdrawal (BCF)
4. Waterfowl Production Areas			
Daniels Co., Montana	19	0.8	
Sheridan Co., Montana	"	0.6	
Divide Co., N.D.	"	0.14	
		1.54	1
Mountrail Co., N.D.	17	.33	2
Sub Total - Waterfowl Prod.		1.87	3
5. National Parks			
Ft. Union Trading Post, Montana Historical Site	19	.07	
Ft. Union Trading Post, N.D.	"	.54	
		0.61	0.5
Custer Battlefield National Monument, Montana	14	1.2	3.5
Sub Total - National Parks		1.81	4.0
Existing and Potential Withdrawal - Total		2073.6	8,499.0
Total - All Tight Gas Formations and Areas -		32730	100,188
Existing and Potential Withdrawal as % of Total		6.3	8.5

- Greater Green River Basin, Wyoming (See Table 83)

Some 15 BLM wilderness study areas constitute the bulk of potentially withdrawn land in this basin. They represent about 4,007 BCF, or 5 percent of the total tight gas resources in the basin. Only one other small area is not available -- a portion of the Seedskadee wildlife refuge along the Green River.

Many of the BLM wilderness study areas in this basin are in areas of active oil and gas operations. Prior to being designated wilderness study areas, a number of oil and gas leases had been obtained on some of them and active operations had begun. BLM officials indicate that some of these operations will probably be allowed to continue while the wilderness studies are conducted and possibly after the areas are declared wilderness by Congress. Thus, the acreage actually withdrawn will probably be significantly less than the total potential withdrawal.

There are two large areas in this basin under the jurisdiction of the Water and Power Resources Service (formerly the U.S. Bureau of Reclamation) and one large national recreation area along the Green River in the vicinity of the Flaming Gorge Reservoir. These areas are, however, open to oil and gas leasing.

- Piceance Basin, Colorado (See Table 84)

There are only two wilderness study areas in the tight gas area of this basin, covering only about 43 sections of land. These two tracts represent about 410 BCF of resources, or about 1 percent of total tight gas resources in the basin. There are no RARE II areas, wildlife refuges, or national parks in the tight gas area. There is one large oil shale withdrawal area in the basin, but this area is open to oil and gas leasing and already has a number of leases on it.

- Uinta Basin, Utah (See Table 85)

A portion of a large wilderness study area (25 percent) constitutes the major potential withdrawal of gas resources in this basin. Also a portion of a small wildlife refuge (20 percent) constitutes withdrawn resources in the area amounting to only 13 BCF. Together, these two areas represent about 146 BCF of tight gas resources, or about 1 percent of total tight gas resources in the basin. The basin also contains a sizable naval oil shale withdrawal tract, but this area is not closed to oil and gas leasing.

- Wind River Basin, Wyoming (See Table 86)

Only one existing USFS wilderness and one BLM wilderness study area are located within the tight gas area of this basin. Together they represent 328 BCF of resources, or about 1.4 percent of total tight gas resources in the basin. This basin also contains a large area designated for land reclamation by the Water and Power Resources Service. It is situated within an Indian reservation; however, the reclamation area is not closed to oil and gas leasing.

TABLE 83

Greater Green River Basin - Wyoming
Existing and Potential Federal Tight Gas Land
and Resources Withdrawal

	Potential Land Withdrawal Sections	Potential Gas Resources Withdrawal (BCF)
1. Wilderness Study Areas		
040-311 Alkali Draw and Bush Rim (65%)	17.3	
040-313 South Pinnacles	16.9	
040-316/317 Alkali Basin and E.Sand Dunes	20.0	
040-318 Red Lake	14.9	
Sub Total - Lewin Area #1	69.1	817
040-408 Adobe Town	81.5	
030-401 Adobe Town	51.6	
Sub Total - Lewin Area #6	133.1	1,851
040-323 Honeycomb Buttes - E 1/2 Lewin #4	65.0	944
040-306 Buffalo Hump	16.1	
040-307 Sand Dunes (15%)	6.4	
040-401/402 Devil's Playground and Twin Buttes	37.9	
040-406/407/410 Red Creek Badlands and Teepee Mountain (75%)	6.7	
Sub Total - W 1/2 Lewin #4, Lewin #5, Bridger, West Moxa Arch	67.1	395
Total Wilderness Study Areas	334.3	4,007
2. Wildlife Refuges		
Seedskadee - W 1/2 Lewin #4, etc. (20%)	3.3	15
Total Existing - Potential Withdrawal	337.6	4,022
Total - All Tight Gas Formations and Areas in Basin	8,938.0	81,762
Existing and Potential Withdrawal as % of Total	3.8	4.9

TABLE 84

Piceance Basin - Colorado
Existing and Potential Federal Tight Gas Land
and Resources Withdrawal

	Potential Land Withdrawal Sections	Potential Gas Resources Withdrawal (BCF)
1. Wilderness Study Areas		
007A - Black Mountain Unit/Berry Point	15.5	312
066 Little Bookcliff Unit (60%)	27.8	98
Total Potential Withdrawal	43.3	410
Total-All Tight Gas Formations and Areas in Basin	3,171	32,979
Potential Withdrawal as % of Total	1.4	1.2

TABLE 85

Uinta Basin - Utah
Potential Federal Tight Gas Land & Resources Withdrawal

	Potential Land Withdrawal Sections	Potential Gas Resources Withdrawal (BCF)
1. Wilderness Study Areas 068A Desolation Gray Unit - Rattlesnake Canyon (25% est.)	11	133
2. Wildlife Refuge		
Ouray - (20%)	1.1	13
Total Existing and Potential Withdrawal	12.1	146
Total-All Tight Gas Formations and Areas in Basin	1,184	15,269
Existing and Potential Withdrawal as % of Total	1	1

TABLE 86

Wind River Basin - Wyoming
Existing and Potential Federal Tight Gas
Land and Resources Withdrawal

	Potential Land Withdrawal Sections	Potential Gas Resources Withdrawal (BCF)
1. Existing Wilderness Fitzpatrick-Forest Service (15%)	36	116
2. Wilderness Study Areas - BLM WY30-111-Copper Mountain	10.7	212
Total Existing and Potential Withdrawal	46.7	328
Total-All Tight Gas Formations and Areas in Basin	2,280	23,286
Existing and Potential Withdrawal as % of Total	2.0	1.4

- Denver Basin, Colorado, Wyoming, and Nebraska

There are no BLM wilderness study areas, RARE II proposed wilderness areas, wildlife refuges, or national parks in the tight gas areas of the Denver basin.

- San Juan Basin, New Mexico

There are a number of BLM wilderness study areas and RARE II proposed wildernesses in New Mexico, but there are none in the tight gas areas of the San Juan basin. The tight gas area does contain Indian legislation land to which the federal government owns the mineral rights along with some reclamation land, but these are all open to oil and gas leasing. The Atomic Energy Commission set aside some small tracts with uranium potential, but they are not large enough to be of withdrawal significance. There are no wildlife refuges, waterfowl protection tracts, or national parks in the tight gas portion of the basin.

- Cotton Valley Basin, Texas and Louisiana

The tight gas prospective area in this basin begins in eastern Texas and stretches across most of northern Louisiana. There are some RARE II tracts in eastern Texas and northern Louisiana near this basin, but none are actually located in it. The basin does not contain any national parks or wilderness study areas. (In Texas, there are no wilderness study areas at all since the BLM

owns very little land in Texas. When Texas was admitted to the Union, it retained all of its land and none was assigned to the public domain.)

- Edwards Lime Trend, and Val Verde-Sonora and Ozona Basins, Texas

The Edwards Lime Trend extends across a portion of south central Texas. The Val Verde-Sonora and Ozona basins are situated in southwestern and western Texas. The Big Bend National Park and the Guadaloupe Mountains wilderness are in the general vicinity of these basins, but not in them. There are no RARE II wilderness areas or wildlife refuges in these basins.

Restrictions on Oil and Gas Development Within Federally Designated Wilderness Study Areas and Wilderness Areas

BLM Wilderness Study Areas

Pre-Federal Land Policy and Management Act Leases Prior to Being Designated Wilderness by Congress -- Leases with Physical Impairment. All exploration, drilling, and production facility contruction activities begun on oil and gas leases in wilderness study areas prior to the 1976 Federal Land Policy and Management Act are permitted to continue so long as their physical impairment effects do not exceed in manner and degree that which had already occurred. A more specific definition of "manner and degree" of impairment is found in the description of the "grandfathered" concept.

A grandfathered use will be permitted if it has created actual physical impact on the land but has not necessarily resulted in an oil or gas discovery. In this case, the quantity of on-ground impacts may be increased at a logical pace, but the impacts may not be of a significantly different type. For instance, if exploration wells had already been drilled on a lease, additional exploration wells could be drilled. If discovery wells could then go to the production stage without causing new impacts of a significantly different kind, this too could be permitted (e.g., this would be the case if pipelines, power lines, tank batteries, and pumpjacks were installed on already disturbed sites and routes).

Pre-Federal Land Policy and Management Act Leases Prior to Being Designated Wilderness by Congress -- Leases with No Physical Impairment. If leases were held in wilderness study areas prior to the Federal Land Policy and Management Act on which no impacts had been made by oil and gas activities, it is permissible to undertake oil and gas exploration and drilling activities if these activities meet the nonimpairment criteria established by the BLM, including:

- Oil and gas activities may be temporary and will be terminated if the areas are designated as wilderness by the President and Congress.

- Any effect caused by oil and gas activity can be reclaimed to a condition which is substantially unnoticeable. The operation will be required to undertake this reclamation at the time the BLM submits its wilderness recommendation to the Congress.

- After reclamation, the wilderness values of the area must not have been degraded sufficiently to affect its recommendations to Congress as a wilderness area.

Post-Federal Land Policy and Management Act Oil and Gas Leases -- Leases Obtained Prior to Interim Management Policy Guidelines and Prior to Being Declared Wilderness by Congress. All post-Federal Land Policy and Management Act leases obtained prior to the interim management policy guidelines (December 1979) are subject to a special wilderness stipulation. This stipulation states that oil and gas activities will be permitted as long as the BLM determines that they will not impair wilderness suitability. To be nonimpairing, activities must meet the following criteria:

- Use may be temporary, and, if terminated, reclamation requirements will be met.

- Wilderness values must not suffer to the extent that the area's suitability as a wilderness is affected.

- Effects of activities must be capable of reclamation.

Areas Declared Wilderness by Congress. If any part of an oil and gas lease is designated wilderness by Congress, any exploration and development activities taking place at present or in the future on that part of the lease will remain subject to the requirements of the wilderness protection stipulation, except as modified by the Act of Congress designating the land as wilderness. If Congress does not specify how leases will be managed, provisions of the Wilderness Act of 1964 will apply, as implemented by the Department of the Interior.

Forest Service Wilderness Areas

Proposed Wilderness Areas. Normally issuance of oil and gas leases will not be recommended in these areas unless methods can be used which avoid surface occupancy or if surface occupancy will not significantly degrade wilderness values. However, a lease cannot be rejected solely because it is within a wilderness area. The Chief of the Forest Service has the responsibility for recommending leases and their terms in national forest proposed wilderness areas.

Further Planning Areas. Oil and gas exploration in these areas will be permitted only on a case-by-case basis and only if the operator agrees to incorporate a stipulation indicating that exploration will be for the purpose of determining the extent of any oil or gas resources. Any development or production

operations must receive specific approval by the Forest Service based on a land management plan and eventual classification of the land by Congress.

Non-Wilderness Areas. New leases and operations under existing leases were authorized in those areas classified as nonwilderness beginning April 15, 1979. These actions will be taken in accordance with usual Forest Service procedures which apply to roadless areas.

Other Federally Designated Wilderness Areas

National Park Wilderness Areas. For all practical purposes, oil and gas operations are prohibited on all national parkland whether it be classified wilderness or nonwilderness. However, a few leases have been allowed in the past by the Congress on land with mineral production potential. One example is the Glen Canyon Recreation Area in Utah and Arizona. Also, in one instance in North Dakota, leases were allowed on parklands which were being drained by wells adjacent to the parkland.

Wildlife Refuge Areas. Oil and gas operations on wildlife refuge land are prohibited with rare exception. For example, leases have been allowed on wildlife land being drained by adjacent wells. Also, geophysical surveying on wildlife land has been allowed to permit continuity in data sampling by exploration companies. This contributes to subsurface mapping for drilling on land in the vicinity of wildlife refuges.

Some Practical Consequences of Areas Being Designated Proposed Wilderness

The previous discussion of restrictions on oil and gas activities on potential BLM and USFS wilderness land indicates that exploration and production are permitted under certain conditions. However, these operations may not be permitted to continue if the area is ultimately declared an official wilderness area by Congress. If this is the case, any previous discoveries could possibly not be exploited and production may be discontinued. This would be a strong deterrent to any exploration and development in the areas.

Environmental Considerations

An increase in tight gas production will undoubtedly have an effect on the environment. The effects of such an incremental increase can be measured as the benefits derived from decreased emissions associated with the reduced use of other fuels as they are replaced with tight gas. The increased development of tight gas will probably improve the quality of the environment.

Gas Price Regulations

The regulation of gas prices which have been controlled below the energy equivalent oil price has been a major disincentive to

gas production. Price controls on gas, which have existed since 1954, have recently begun phased decontrol under the Natural Gas Policy Act of 1978. This phased deregulation now in progress will be completed in the 1985-1987 period for gas produced from most wells drilled after February 1977. Acting under authority of the NGPA, the Federal Energy Regulatory Commission on August 15, 1980, issued regulations providing a ceiling incentive price for gas produced from tight gas formations (see Appendix G for FERC regulation). They set a ceiling price of $4.586/MMBtu as of September 22, 1980, for gas produced from tight gas formations, the price to be adjusted for inflation as measured by the GNP intrinsic deflator on a monthly basis.

These regulations provide for the state regulatory agencies, or the USGS in the case of federal lands, to nominate tight gas formations. FERC will approve the nominations, after which gas produced after July 15, 1979, from a new well or a new recompletion in the tight gas formation may receive the incentive ceiling price, if purchasers are willing to pay this price. This ceiling price limitation will expire on January 1, 1985, or July 1, 1987, along with price controls on other gas from most new onshore wells.

State regulatory agencies have held hearings on tight gas formation nominations in Colorado, New Mexico, Texas, Utah, Wyoming, and possibly other states. Table 87 shows formations that have been nominated by the state agencies to FERC as of October 27, 1980. These should all be acted upon and probably approved by the end of 1980.

The FERC has made a major contribution to the development of tight gas by this ruling. The new tight gas ceiling price is set at twice the conventional gas ceiling price for five years. Many operators will be encouraged to develop tight gas plays. The application of the incentive price to recompletion of old wells and to new tight gas formation gas wells will bring new gas supplies into the market more rapidly.

In evaluating a tight gas play, operators may find the economic summaries of interest in the basin chapters of Part II of this report. All of the economics in the report are based on cost and prices in constant dollars as of January 1, 1979. To use these economics it is necessary to correct them for inflation. The $4.586/MMBtu price on September 22, 1980, is equivalent to a price of $3.33/MCF in January 1, 1979, dollars in the report. This report assumes that 1,000 cubic feet of gas has a heating value of 1 MMBtu. This adjustment was made by the IPAA price index for drilling and equipping wells. The cost of finding and producing tight gas should follow the Drilling Cost Index closely.

The Drilling Cost Index was 176.0 on January 1, 1979, and its estimated value on September 22, 1980, was 242.3. The price adjustment was calculated as follows: (September 22, 1980, dollars) $4.586 x 176.0 divided by 242.3 = $3.33 (January 1, 1979, dollars). To use these prices in the report for a date in the future, they may be adjusted forward by this formula: future price = (price in

TABLE 87

Formations Nominated by State Regulatory Agencies
for Designation as Tight Formations

State	County	Trend	Formation
Texas (1)	Many in N.E. Texas	Cotton Valley	Cotton Valley Sand* Cotton Valley Lime Bossier Shale
Texas (2)	Crockett, Edwards, Schleicher, Sutton, Terrell, Val Verde	Canyon Sandstone	Sonora, Ozona
Texas (3)	Reagan		Cisco
Texas (4)	Hidalgo	Vicksburg	U, V
Texas (5)	Hidalgo	Vicksburg	Y
Wyoming (1)	Sweetwater, Uinta, Lincoln		Frontier
Wyoming (2)	Sweetwater, Carbon		Mesaverde
New Mexico (1)	Lea		Austin-Mississippian
Louisiana (1)	Union		Arkadelphia
Colorado (1)	Weld, Adams, Boulder		Wattenberg "J"
Colorado (2)	Rio Blanco, Garfield		Mancos "B"
Colorado (3)	Cheyenne, Kit Carson, Lincoln, Logan, Phillips, Sedgewick, Washington, Yuma		Niobrara
Colorado (4)	Rio Blanco		Fort Union, Mancos, Mesaverde
Colorado (5)	Mesa		Rollins, Corcoran, Cozette
Colorado (6)	Rio Blanco		Mancos "B"

*Approved by the Federal Energy Regulatory Commission effective October 24, 1980.

the report) x (IPAA index for future date divided by 176.0). FERC uses the GNP intrinsic deflator to adjust its ceiling prices forward. On this basis, FERC estimated the ceiling price for tight gas on January 1, 1979, as $3.96/MMBtu. The GNP intrinsic deflator will not properly adjust the economics in the report to a future or past date.

Chapter Seven

EXPLORATION AND PRODUCTION TECHNOLOGY CURRENT AND ADVANCED

EXPLORATION TECHNOLOGY

Current Exploration Methods

Geological

The geological technology used to explore for tight gas reservoirs does not differ appreciably from that used in exploration for conventional reservoirs, whether oil or gas bearing. The principal differences in approach are primarily of degree rather than of kind. Basically, exploration involves reservoir and trap predictions, reservoir evaluations, and determinations of natural gas potential; i.e., the availability of hydrocarbon gas as a result of thermal generation, migration, entrapment, and preservation, or as a result of bacterial generation and preservation. Scientific disciplines commonly needed for a thorough study of tight gas reservoirs encompass the entire spectrum of available geological technology; i.e., stratigraphy, sedimentology, petrology, mineralogy, petrophysics, well log interpretation, geochemistry, structural geology, statistics, palynology, paleontology, and computer science.

Reservoir/trap predictions entail:

- Locating porous and permeable beds
- Determining their stratigraphic and areal distributions and configurations
- Determining their age and correlating equivalent stratigraphic units
- Determining stratigraphic and geographic proximity to related and associated reservoirs; e.g., frequency of occurrences of lenses and stacking of multiple reservoirs
- Determining or predicting types of trapping mechanisms
- Locating effective reservoir seals
- Interpreting possible reservoir discontinuities caused by faulting, nonconformities, intrusions, channels, etc., or repetition caused by faulting.

Reservoir evaluation of an exploratory nature, mainly based on wildcat well samples and well data, involves:

- Mapping and zoning of porosity and permeability

- Determining porosity and permeability qualitatively and quantitatively
- Determining pore throat shapes and sizes
- Determining water saturation and water distribution in micropores and macropores as free and adsorbed water
- Analyzing salinity and composition of any recovered water, and composition of other recovered fluids
- Evaluating log responses
- Determining temperature and pressure relative to burial depth
- Studying petrology and mineralogy
- Measuring mechanical properties
- Studying diagenetic history; e.g., cementing materials, mode of origin and sequence of cementation, weathering, leaching, dissolution, replacement, overgrowths
- Identifying organic matter and oil residue, if any, as to type, quantity, and effect on reservoir producibility
- Studying of occurrences of natural fractures, stylolites, bedding features, and sedimentary structures such as burrows, and their influence on fluid flow
- Assessing fluid producibility rates and duration
- Estimating reservoir capacity and in-place and recoverable reserves
- Assessing potentially damaging procedures on tight gas reservoir performance from drilling, testing, stimulating, completing, and producing wells.

Essentially every well drilled for tight gas reservoir production, whether a reservoir is blanket or lenticular, has considerable risk because the productive potential of a well is uncertain until the reservoir is stimulated. Consequently, more emphasis must be placed on evaluating reservoir properties than is necessary for conventional reservoirs. The state of the art is such that a general outline of a productive trend or fairway can usually be readily determined by relatively few scattered wells, but the selection of economically productive well sites and the elimination of uneconomical sites prior to drilling generally remain uncertain until a considerable density of wells has been achieved.

In certain geological provinces with gas prospects in tight reservoirs, it is important to determine the availability of generated hydrocarbon gases because gas accumulations commonly are not

coextensive within the confines of a productive basin. These restricted occurrences of gas are attributable to three principal controls: source bed distribution, generation-expulsion performance, and preservation of trapped reservoir gas. Failure to take these limiting factors into account has at times resulted in excessively high estimates of in-place and recoverable reservoir gas.

Limited areal and stratigraphic distribution of effective thermal gas source beds is common to many basins. The Denver basin is a good example, as are the Williston and Powder River basins. Most basins have retained considerably less than half of the thermal gas generated and expelled within them, particularly those basins in which gas explusion occurred before Late Tertiary time, or those which lack highly effective seals such as evaporites. Also, gas preservation tends to be poor in areas and zones of meteoric recharge water encroachment, except in highly protected traps.

A determination of the amount of gas available for tight gas reservoirs requires consideration of both thermal and biogenic sources. Assessment of effective source rocks for thermal gas can be based on the distribution, volume, and generating capability (quantity, quality, and type of organic matter) of the source rocks, as well as on their thermal carbonization stages and thermal histories. From this information, the time(s) of gas expulsion can be estimated; this includes gas expelled with oil if the source is oil (i.e., Type II organic matter), wet gas expulsion if the source is wet gas, and essentially dry gas if former oil has attained the later gas-expulsion stage. It also includes gas expelled from gas source rocks that never had an oil-generating capability (i.e., Type III organic matter). Lastly, it includes estimates of gas formed by thermal cracking of oil to gas in reservoirs as well as in oil source rocks, the latter requiring additional estimates of amounts of gas expelled.

Obtaining estimates of quantities of thermal gas expelled from source rocks, and of hydrocarbon gas formed by cracking crude oil external to source rocks, is only the first step in evaluating the gas-producing potential of various provinces. It is also essential to obtain realistic estimates of the amounts of gas preserved. Preservation is dependent on a number of factors, such as time of expulsion and entrapment (and hence, time to escape), effectiveness of seals, temperatures, pressures, and burial depths, and tends to be better in zones with relatively low temperatures and either anomalously high or anomalously low pressures (indicating that seals are intact). A comparatively unknown negative factor in preservation, particularly at low temperatures, is the role of methane-consuming bacteria in the subsurface.

Geophysical

In exploration for tight gas reservoirs, geophysical (and specifically seismic) technology has been successfully employed in delineating zones of lithologic contrast, but it has been of limited usefulness in defining reservoirs and traps and in locating drillable prospects. The limitations stem from the nonstructural nature of most tight gas reservoir traps, and from the poor quality

of tight reservoir rocks; i.e., low density and velocity contrasts because of their generally low porosities and relatively low quantities of in-place gas. With the conditions prevailing in many tight gas reservoirs, substantial improvements in geophysical technology will be needed before it can become an important exploration tool capable of discriminating between tight gas reservoir traps and the geologically similar background.

Bright-spot techniques have not been particularly helpful in the discernment of low grade gas accumulations because of the minor density and velocity contrasts, especially in older rocks. Occasionally, seismic work has successfully identified highly overpressured zones encompassing tight gas reservoirs.

The main role of seismic technology appears to be in helping to resolve production problems related to massive hydraulic fracturing; e.g., fracture orientation and dimensions.

Well Logging

The tolerance for error in well log evaluation of tight gas reservoirs is much less than that in evaluations of conventional reservoirs again because of the shale-like character of most tight gas reservoirs. The log character of reservoir rocks is often similar to the characteristics imparted by nonreservoir rocks. More sensitive and discriminatory measuring devices are needed because existing logging technology seems to be of little value in resolving problems pertaining to permeability and water saturation. Porosity determination can be difficult, especially where a borehole is enlarged.

The density, sonic, and resistivity logs are generally the most useful of currently available logging suites in evaluating tight gas reservoirs. Nuclear magnetic resonance (NMR) logs and borehole gravimeter surveys show possible promise under certain conditions for determining adsorbed "shale" water from free "reservoir" water, and for interpreting prospective pay zones.

Potential for Improved Exploration Technology

Basic technological developments that would appreciably improve the present exploratory well success ratio in tight gas reservoirs do not appear likely in the foreseeable future. However, the success ratio can be expected to improve gradually with refinements in existing methodology. Also, increased well control will lead to greater comprehension of the factors that control technical and economic recoveries of gas from tight gas reservoirs. This will lead to improved correlations and predictions of potentially productive rock units.

Additional improvements in the exploratory success ratio will result if economic exploration incentives match or outpace escalating exploration costs. Improvements in exploration technology will be an inevitable consequence of any stimulus to exploration activity. Success will feed on itself, assuring much needed additional energy to help sustain the nation's economy.

Specifically, improvements in methodology can be expected in the following areas of geological input relative to tight gas reservoir technology:

- Predicting lenticular sandstone geometry and orientation
- Predicting favorable permeability trends within low porosity, low permeability reservoirs
- Determining physical properties and other geological factors that control fracture orientation and fracture dimensions in reservoir rocks
- Calculating effective source rock volume for gas, and gas source rock performance; i.e., amounts of gas generated and expelled, times of explusion, amounts of gas derived from thermal cracking of crude oil, and amounts of gas preserved
- Differentiating thermal gas from bacteria-generated gas
- Determining producibility by means of conventional core analysis of tight gas reservoirs, and obtaining more accurate in situ gas permeability measurements, using appropriate correction factors to bring core analyses more into line with permeabilities derived from reservoir flow tests
- Predicting and avoiding potential reservoir damage situations
- Determining pay thickness, porosity, water saturation, and gas content by means of well logging devices and log interpretations
- Comprehending physical, chemical, and biological diagenetic processes and the ability to predict favorable vs. unfavorable diagenetic settings
- Predicting orientations and "openness" of natural fracture sets and systems and their influence on massive hydraulic fracturing (several new well logging and seismic techniques will help accomplish these measurements)
- Distinguishing between tectonic fractures and fluid-press pressure-induced natural fractures
- Determining free and adsorbed water
- Determining amounts of in-place and recoverable gas and the influence of gas desorption and long-term producibility
- Determining seismic definition of tight gas reservoirs and contrasts caused by abnormally high and low reservoir pressures.

Dual shear/P-wave interpretational techniques, in particular, offer promise of enabling geophysicists to identify and delineate tight gas-bearing reservoirs within the next decade.

Tight gas reservoir exploration is generally not affected by a number of the problems frequently encountered in more conventional exploration, as problems attendant with exploratory drilling of wells to great depths or in high temperature rocks usually will not be encountered. Arctic drilling and offshore marine drilling will not be needed in the foreseeable future.

High concentrations of hydrogen sulfide (H_2S) and other non-hydrocarbon gases are not likely in the majority of tight reservoir gas plays, nor are land subsidence and limited accessibility common problems.

PRODUCTION TECHNOLOGY

It is not economically feasible to develop and produce the large quantities of natural gas trapped in tight gas reservoirs without special stimulation techniques such as massive hydraulic fracturing. In the low permeability reservoirs, the rock matrix pore throats are so small and/or sparse that they severely restrict the rate of gas migration into a well; this drastically affects both producing rate and cumulative recovery. An example of the comparative production between a typical tight gas reservoir and a typical conventional permeability reservoir is shown in Table 88. This shows production rates and cumulative production for two permeability values; i.e., a conventional reservoir of 10.0 md and a tight reservoir of 0.001 md for the unfractured case. Also shown is production from a tight reservoir (.001 md) with a 4,000-foot fracture. All other reservoir properties are identical except for permeability and the existence of a 4,000-foot fracture.

The problems in recovery are compounded by the fact that these reservoirs typically have low bulk porosities and sometimes high water saturations, resulting in low gas-filled porosity. In addition, the nature of the reservoirs can vary widely. Some are continuous (or blanket) reservoirs, while others are lenticular. In the lenticular reservoirs, discontinuous sand lenses which may not intersect the well bore restrict the potential drainage of an individual well. These lenses can vary in width, length, thickness, and curvature (like meandering streams). Both the blanket and lenticular deposits are usually found dispersed in massive shale or siltstone sections typically from 500 to 3,000 feet thick. It is possible for lenses throughout the entire section to have some gas saturation; however, the more porous sand zones constitute the resource target. The technological problems associated with recovering gas from tight lenticular sands are considerably more severe than recovery problems in continuous reservoirs.

TABLE 88

Comparative Production Rates
Conventional vs. Tight Gas Reservoirs*
(MMCF/Yr)

Year	Conventional (10.0 md)	Tight (0.001 md)	
	x_f=100'	x_f=100'	x_f=4,000'
1	22,000	21	798
2	3,770	18	437
5	240	16	269
10	6	13	187
20	0	12	137
30	0	11	114
Ultimate 30-Yr Cumulative MMCF	31,700†	390	6,015

*Computed for a typical 0.65 gravity gas in a 2:1, 1,280-acre, rectangular, 85-foot thick, 250°F reservoir with a well bore flowing and initial pressure of 550 and 5,500 psig, respectively, and a hydrocarbon pore volume of 2.9 percent.

†Reservoir totally depleted in 10.5 years.

Note: x_f (fracture length, well bore to tip) of 100' usually occur with standard perforation breakdown procedure.

Fracturing Technology

These tight gas reservoirs require highly conductive drainage channels which penetrate deeply into the extremities of the formation to drain gas into the well bore. The leading method of feasibly and economically creating these flow paths is massive hydraulic fracturing. These treatments create a deeply penetrating, vertical fracture propped open with sand or another suitable propping agent. (See Figure 39 for an illustration of the massive frac concept.) For each producing interval there is usually only one main fracture in each producing zone, and it extends on both sides of the well. In many blanket-type sands, such propped fractures can now usually be extended and propped open for distances on the order of 1,000 feet along each vertical wing on either side of the well. It has been assumed that similar lengths can possibly be achieved for lenticular sands. It may be difficult to achieve 1,000-foot lengths with base technology in some lenticular formations. Vertical growth tendencies of hydraulic fractures in lenticular zones are usually greater than in blanket formations. This vertical growth can result in a shorter than desired fracture length. (In the trade literature, the term "fracture length" refers to the length of one wing. It is one half of the length from

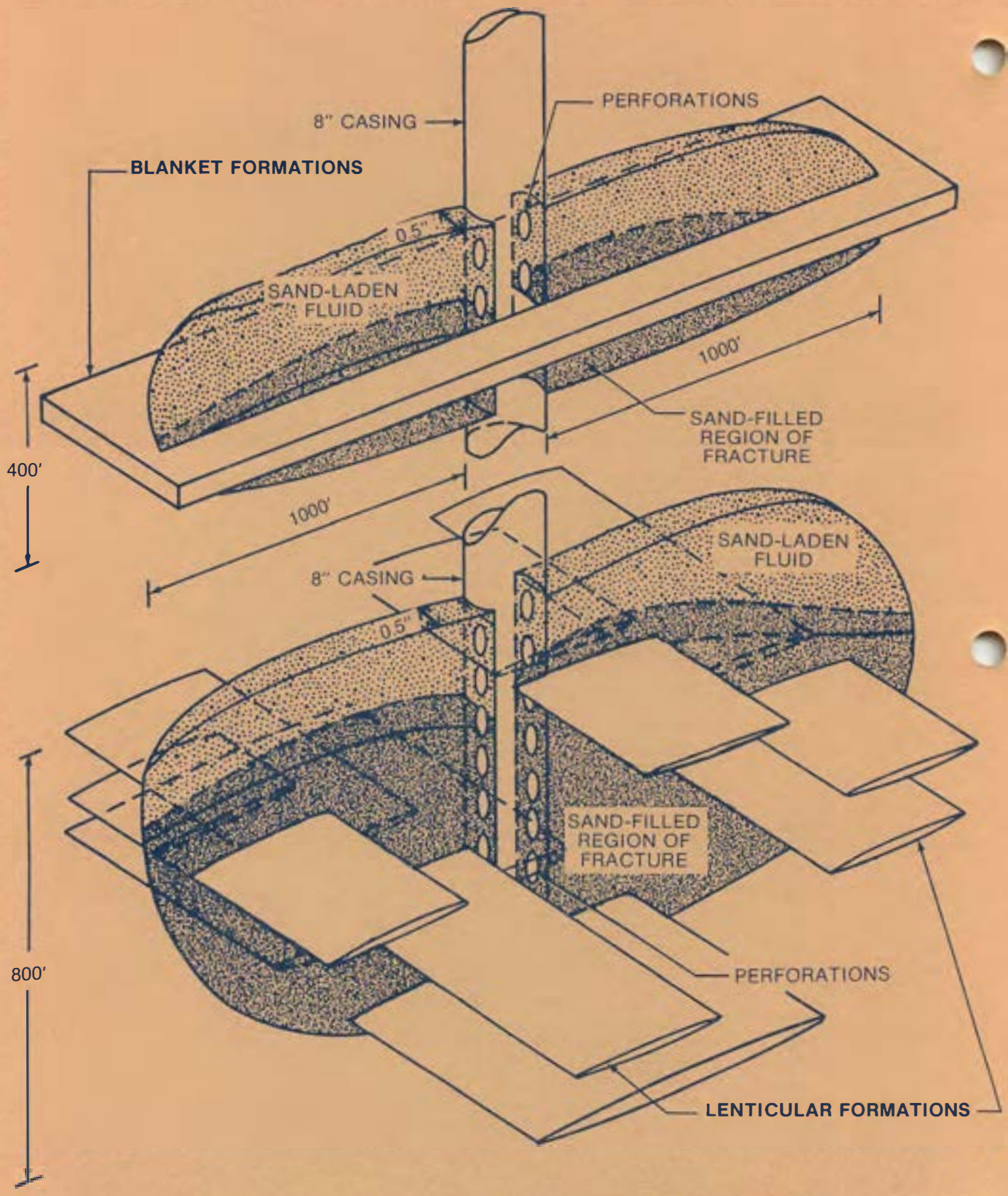


Figure 39. Conceptual Fractures Created by MHF for Blanket and Lenticular Formations.

tip to tip.) These conductive, propped fractures create a major pressure sink into which fluids in the exposed tight rock section can flow out of the formation into the fracture and move freely on to the well bore through a "freeway." This stimulates producing rates and increases ultimate recovery despite low permeability.

The fractures are created by pumping a special fracturing fluid (typically either gelled water, gelled hydrocarbon, foam, or a hydrocarbon/water emulsion) into the selected formation at sufficient pressure to break the rock. As more fluid is pumped, the fracture extends further into the reservoir rock, being propagated in both directions from the well bore. Due to earth stresses, the fractures are nearly always oriented in a more or less vertical plane. A propping agent, usually sand, is mixed with the fluid and is carried into the fracture by the fluid. When the designed volume of fluid and proppant has been injected, pumping is stopped and the pressure is decreased, allowing the fracture to close on the proppant. Afterwards, when the wellhead is opened for production, expansion of the gas near the fracture face forces the fracturing fluid out of the fracture and up the well (the cleanup phase), but leaves the proppant so that the fracture faces do not "heal."

Most of the successful fracturing activity to date has been concentrated in the geologically favorable portions of the blanket formations. The majority of the production is from the Cotton Valley, Denver, Green River, San Juan, and Sonora basins. Most formations that have been stimulated to date in these basins have been the broad, continuous blanket reservoirs with conditions that favor effective MHF treatments. The Sonora, however, is lenticular, but is unique among the tight formation studies to date in that its lenses are large enough to approximate the drainage area of a comparable blanket formation. Production from the other lenticular basins has been primarily from the one- or two-blanket-type formations they contain. Inconsistent results of tests in the other basins have restricted development to date, emphasizing the need for technological advancements to overcome the problems they pose. More than 1,000 MHF treatments of several types in many different geological environments have been performed in the last six years. In general, these tight gas completions have steep declines in production rates (depending on permeability) during the first few years and continue with lower rates of decline for 20 to 30 years.

With the current technology, MHF treatments typically range in size from 100,000 to 1,000,000 gallons of fracturing fluid with up to 2.5 million pounds of propping agent. These treatments produce fractures of varying lengths and conductivities. The effective conductive fracture length will depend on many factors, including the volumes and types of materials pumped, the interaction of the in situ rock properties and in situ stress fields with the internal stresses created by the fluid(s), and the proppant strength and manner in which it is distributed in the fracture. The current

methods of creating effective conductive fracture lengths are limited to controlling:

- The volume and type of fluid
- The volume and type of proppant
- The injection rate
- The fluid and proppant pumping schedule.

The Effects of Developing Advanced Technology

The industry is gradually moving up a learning curve; however, to make further significant advances, some major research requirements are being recognized as prerequisite to effective exploitation of some major tight sand reservoirs. With what is termed base technology (which includes current available technology plus expected evolution from trial and error application), it is estimated that eventually effectively propped fracture lengths of 1,000 feet (from well bore to tip) and conductivities of 500 md-ft can be created in practically all of the basins included in this study. In some formations (particularly the blanket type), it is currently often possible to achieve longer, higher conductivity fractures. However, these are currently special situations and the capability of "universally" achieving longer, more conductive fractures in any formation (especially lenticular) will require significant additional advances in technology. With advanced technology, it is postulated that effectively propped fracture lengths on the order of 4,000 feet (from well bore to tip) with conductivities of 1,000 md-ft will ultimately be possible in all basins.

This advanced technology increase in effectively propped fracture length and fracture conductivity will be accompanied by reductions in vertical fracture growth (fracture height). Also, it will be possible to transport proppant farther down the hydraulically created fracture. These two factors will result in more efficient use of fracturing materials and will ultimately reduce the cost per unit-length of effectively propped fracture. In addition to more efficient methods for creating longer, higher conductivity fractures, advanced technology is expected to provide an a priori knowledge of the azimuthal direction which hydraulic fractures will tend to follow. This will have a major impact on the strategic design of well location patterns to maximize reservoir drainage with minimum interference between drainage patterns for each well. Under base technology, fracture azimuth is essentially unknown. This somewhat limits well density because of the potentially adverse effects of creating well drainage patterns which overlap and interfere with each other, constituting an inefficient and highly costly process for reservoir depletion. Knowledge of fracture azimuth tendencies will provide a basis for selectively locating well patterns with the appropriate number of wells necessary to efficiently drain the entire reservoir and minimize the potential for interference.

Table 89 reflects the base and advanced technology pertinent to fracturing as it is currently viewed. The data represent what is considered typical technology for tight gas reservoirs in general; i.e., technology which can be more or less universally applied to blanket or lenticular formations in any one of the basins included in this study. The base data represent a composite of experience gained throughout the oil and gas industry on some 1,000 tight gas wells treated by MHF over the past seven years. The advanced case was developed from a composite of projections obtained from those segments of the industry which had gained experience in the development, MHF stimulation, and production of these 1,000 wells in tight gas formations. However, advanced case technology represents technology yet to be developed.

The preceding comments briefly addressed the aspects of fracture height, conductivity, effectively propped length, hydraulic length, and well spacing for base vs. advanced technology in blanket and lenticular formations. One additional comment pertains to the relationship between permeability and fracture length in the advanced case. In blanket formations, 2,000-foot-long conductive fractures are adequate for formations with permeabilities of 0.1 md or higher. Additional fracture lengths in these formations will not effect a significant increase in producing rate or ultimate recovery. Hence, the cost to achieve longer fracture lengths is not justified. For reservoirs with permeabilities of less than 0.1 md, conductive fracture lengths of 4,000 feet or longer are required for adequate reservoir drainage, and are cost justified. In lenticular reservoirs, 4,000-foot-long fractures are necessary for all permeability levels to ensure that the maximum number of lenses remote to a well bore can be intersected and connected to the well bore.

The production rates and 30-year cumulative recovery estimates cited for each basin are based on simulator-calculated predictions for reservoirs producing through fracture systems that conform to the data in Table 89. The method used for making these predictions is discussed in Appendix C, entitled "Cumulative Recovery and Average Gas Producing Rate Calculations." The producing rates and 30-year cumulative recoveries are listed for both the base and advanced cases in the tables entitled "Well Production Summaries" in each basin chapter in Part II of this report. The methods and design data used to compute the MHF volume requirements and treatment costs to achieve the fractures are dicussed in Appendix D, in the section entitled "Fracturing Costs."

TABLE 89

Base vs. Advanced Technology and Regulation

	Blanket Formations		Lenticular Formations	
	Base	Advanced	Base	Advanced
1. Fracture Height	4 x Net Pay	3 x Net Pay	6 x Net Pay	4 x Net Pay
Range (ft)	200 - 600	150 - 400	300 - 1,000	200 - 600
2. Fracture Conductivity* (Md-Ft)	500	1,000	500	1,000
3. Fracture Length, Well Bore to Tip (Ft), Permeability $\geq$ 0.1 md				
Effectively Achieved	1,000'	2,000'	1,000'	4,000'
Hydraulic Design Required	1,700'	2,500'	1,700'	5,000'
Permeability < 0.1 md				
Effectively Achieved	1,000'	4,000'	1,000'	4,000'
Hydraulic Design Required	1,700'	5,000'	1,700'	5,000'
4. Field Development				
Wells Per Section (Max.)	4	12	4	12
Acres Per Well (Min.)	160	53	160	53

*Product of fracture permeability and fracture width.

Chapter Eight

DEVELOPMENT OF ADVANCED TECHNOLOGY

POTENTIAL RESERVE AND PRODUCTION INCREASES

It is obvious from information presented in previous chapters that advanced technology is required to enhance development of tight gas formations. Technological advancements will have a major impact on investment economics, gas rate deliverability, and the ultimate volumes of recoverable gas available in tight gas formations. Some perspective of this can be gained from the data listed in Tables 90 and 91.

TABLE 90

Total Recoverable Gas from Tight Reservoirs
(Constant 1979 Dollars)

Price ($/MCF)	Base Case (TCF)	Advanced Case (TCF)	% Increase
2.50	192	331	72
5.00	365	503	38
9.00	403	574	42

TABLE 91

Individual Well Gas Production Summary -- Cotton Valley
(Annual Producing Rate MMCF/Year/Well)

	k = .01 md			k = .001 md		
Year	Base Case	Advanced Case	% Increase	Base Case	Advanced Case	% Increase
1	512	1,423	179	220	798	263
5	211	572	171	80	269	236
10	166	412	148	58	189	222
30	101	221	119	39	114	192
Cumulative 30-Year Recovery (MMCF)						
Total	4,949	12,336	149	1,838	6,013	227

Table 90 reflects the impact of both price and technology on cumulative recovery. As can be seen, it will take a combination of price incentives and technological advancements to maximize gas production from tight gas reservoirs. It is also obvious that

technology will have as much as and possibly more of an impact than price. A more dramatic impression can be gained from Table 91. These data exclude economic considerations and demonstrate comparative physical behavior for base and advanced technology. This shows that individual well performace can be drastically improved with advanced technology.

From an overall viewpoint, the industry has advanced about 20 to 30 percent up the "learning curve" of readily available state-of-the-art technology capable of universal application to all tight gas reservoirs in all basins. To improve the technology will require a significant amount of research on many different aspects of a wide variety of problems associated with exploration, evaluation, stimulation, and production of tight gas reservoirs. The significant problems and needs are discussed in the following sections.

POTENTIAL TECHNOLOGICAL NEEDS FOR TIGHT GAS RESERVOIRS

Many factors affect the development of gas production from tight gas reservoirs. In general, they may be categorized into (1) resource characteristics and reservoir parameters, and (2) recovery and evaluation methods. The technology dealing with resource characteristics and reservoir parameters generally involves areas of geophysics, geology, petrophysics, well logging, and reservoir engineering. The recovery and evaluation methods require the above disciplines plus technology in the areas of well completion, well stimulation, hydraulic fracturing, pressure transient analysis, and production mechanics. Factors associated with these categories are discussed in the following sections.

Resource Characteristics and Reservoir Parameters

Permeability, gas-filled porosity, net pay thickness, and lenticularity are some of the critical reservoir parameters that affect gas production. Additional factors include rock mechanical and chemical properties and regional stress characteristics. Significant variation in reservoir properties within small geographic areas further complicates reservoir assessment. Problems related to various reservoir properties include the following.

Permeability

Permeability is a measure of the capability of a rock to transmit fluids. It controls the velocities of fluids traversing through a formation and is one of the major parameters which control gas producing rate. In situ gas permeabilities of typical tight gas reservoirs may range from 0.0001 to 0.1 md. These reservoirs were considered "dry" by previous conventional standards.

Accurate knowledge of permeability is essential for ascertaining massive hydraulic fracture stimulation requirements and for predicting potential well performance. Knowledge of permeability variance, both as it is stratified vertically and distributed areally, is extremely important to MHF design. Current methods for

obtaining permeability (production tests, pressure buildup tests, cores, etc.) are highly time consuming and exhibit questionable reliability.

Gas-Filled Porosity

This parameter controls the volume of gas contained in a reservoir. Many tight gas basins are marked by high water saturation and/or high clay content combined with low pore volume. Gas-filled porosity, then, is small by conventional standards. It rarely exceeds 10 percent, and in the majority of cases is about 5 percent. Both gas in place and technically recoverable gas are a function of gas-filled porosity. It is a function of both the rock matrix pore volume and the amount of water saturation in the rock pores. Current methods for measuring water saturation have encountered reliability problems.

Net Pay Thickness

Net pay is one of the most important parameters required for reservoir performance evaluation and formation stimulation design. Total gas in place and flow rate are both essentially directly proportional to the thickness of the gas-bearing reservoir. The total net pay is often composed of numerous relatively thin gas-bearing zones interbedded with impermeable shales and water-filled zones. These may be dispersed broadly throughout massive gross geologic sections. Differentiation of the gas-bearing zones from water-filled zones and shales is essential in estimating the net thickness of a reservoir. Interwell correlations partially mitigate the problem in the blanket reservoirs but offer little assistance in lenticular formations. Current methods for determining net pay have a very high probability for error.

Lenticularity

In the areas where the net pay (and promise of recovery) is greatest, a formation may be highly discontinuous or lenticular. Lenticularity severely reduces the drainage volume that can be contacted by a well bore. Beyond limited outcrop studies, little is known about the size, shape, and orientation of the lenses in lenticular reservoirs. These factors greatly limit productivity as compared to that from blanket-type formations.

In Situ Rock Properties and Stresses

The design of effective stimulation technology requires knowledge of the characteristics of both the gas-bearing reservoir and surrounding rock. This includes local stress fields, regional stress fields, mechanical rock properties, chemical rock makeup, etc. Knowing the stresses and rock properties helps determine the pressure required to create an optimum fracture. Both chemical and mechanical analyses of reservoir rock are necessary to assess the possibility of interaction between fracturing fluids, the reservoir rock, and the existing stresses.

Regional Stress and Fracture Azimuth

Regional earth stresses affect the azimuthal trend of a fracture resulting from MHF stimulation. Fracture azimuth cannot be controlled but it might be predicted. In lenticular formations, this information would be critical if the dominant lens orientation were also known. It may be possible to strategically place wells to maximize the number of lenses intersected by fractures. In developing blanket-type reservoirs, knowledge of the preferred fracture azimuth would permit optimal well spacing and development patterns to avoid interwell drainage area interference.

Variability

Experience to date indicates a broad variation of the critical parameters even within the same formation. Permeability routinely varies by orders of magnitude; gas-filled porosities can vary by factors of 2 to 5; net pay can vary by factors of 2 to 50. Few data are available on the distribution of lens size and geometry, but extremely wide variations can be expected. Experience indicates that expensive, time-consuming measurements and analyses made for one well may not be sufficiently applicable to another well in the same basin to design a fracture treatment.

Wide variations can be observed within the relatively narrow confines of adjacent townships even of a proven field in a blanket formation. This has been experienced in the Wattenberg field of the Denver basin. The significance of this is that it substantially reduces the ability to extrapolate from one well to another. Thus, extrapolation over a wide area is difficult. It also increases the risks that must be considered in property evaluation by industry, and increases the requirements for cost-effective routine methods of measuring and interpreting reservoir characteristics.

Current Resource Character and Reservoir Parameters Capabilities and Needs

In very low permeability gas reservoirs, existing methods and tools for measuring critical parameters have been found to be inadequate for accurately characterizing the producing formations. Extremely low permeability renders data from drill stem tests nearly useless. Well logging has failed to adequately distinguish gas-productive from water-productive zones. Net pay thickness and gas-filled porosity are measured with very low reliability. Current coring techniques tend to alter the rock properties prior to laboratory testing. Conventional laboratory tests of permeability have been shown to produce results that vastly overstate actual permeability under reservoir conditions of water saturation and pressure. The distortion is greater at lower permeabilities, where recovery is more sensitive to permeability. Laboratory measurements and tests of rock strength and hardness are only now being developed and standardized. No downhole permeability measurement technique has proved reliable in tight formations. Pressure testing of wells in tight formations requires vastly longer time periods than for conventional formations (e.g., weeks vs. hours) for

comparable precision. Measurements of lens geometry have been limited to studies of outcrops of the formations. The nature and distribution of the subsurface gas-bearing lenses have not been characterized. Reservoir modeling also needs improvement. Competent two-dimensional flow models are available, but three-dimensional models have only begun to be developed and are exceedingly costly to operate.

In brief, present reservoir characterization techniques are inadequate to guide the design of stimulation technology, to evaluate the performance of that technology, or to predict reservoir performance well enough to reduce the risks that must be accounted for when evaluating a prospect for development. A large investment in the well must be made prior to collection of data that permit valid evaluation. Present procedures are either inaccurate or prohibitively expensive (or both) for field-scale application.

The objective of improving diagnostic tools is to improve the precision in measurement and interpretation of the key reservoir parameters that direct the design of the MHF technology and support accurate assessment of the geologic risks of a prospect.

Recovery and Evaluation Methods

The design of fracturing treatments is currently a trial and error process. The lack of ability to directly measure or identify many of the formation characteristics (e.g., in situ stresses and mechanical rock properties, lithological variations, etc.) that control fracture growth, the geometry of the fracture itself during and after MHF, and the proppant location and distribution in the fracture make it extremely difficult to accurately predict fracturing behavior and effectiveness from a given set of design conditions. In the producing areas where fracturing is utilized, it is typical for operators to progress through an extensive process of trying a number of alternative fluids, treatment sizes, and injection procedures to arrive at a set of "standard" treatments that provide "acceptable" results. Blanket-type formations, where most development to date has taken place, can usually be developed more quickly with this approach because the continuity of the reservoir permits more systematic, risk-reducing experimentation. The lenticular formations offer few such advantages.

There are many factors which pertain to the fracturing process. The more significant aspects are discussed in the following comments.

Fracture Geometry

Fracture geometry refers to the height, width, length, shape, symmetry, and configuration of the induced fracture. The central goal is to create a fracture that is effectively propped and remains in the gas reservoir. Excessive vertical propagation reduces the effective length when nonproductive overlying and/or underlying sections are fractured. Similarly, effective fracture length is reduced if the proppant is not distributed adjacent to the pay over

the full length of the induced hydraulic fracture or if it crushes as the fracture closes. Fracture geometry has a major effect on proppant distribution.

Conductivity

The contrast between the fracture conductivity (permeability x fracture width) and the permeability of the reservoir rock controls the effectiveness of the fracture to increase production rate and ultimate recovery. In very low permeability reservoirs, adequate contrast can usually be achieved with sand proppant. When reservoir permeability is higher (e.g., 0.1 md or greater), the flow capacity of the fracture can be a more serious constraint.

Fracturing Fluid Rheology

The fracturing fluids selected for MHF are critical to fracture growth behavior, the distribution and placement of proppants, and the cost of the treatment. Fluids which leak off rapidly into the formation have low efficiency in hydraulically wedging and extending a fracture. Also, the residue filtered off on the fracture face during leakoff can affect the flow behavior of the fluids remaining in the fracture. The "effective" viscosity of the fluid controls the internal fracture pressure and the proppant transporting characteristics. The currently available fluids which are suitable for MHF are very complex, non-Newtonian, non-power-law mixtures. Their behavior is affected by many things, including temperature, temperature history, shear rate and history, time degradation, and chemical contamination. Thus, they are considered to be somewhat "temperamental" in nature. In addition, current technology is unable to reliably predict the rheological behavior and proppant transport characteristics of these fluids with the degree of accuracy required for optimum fracture design.

Proppant-Fluid Systems Design

Fluids must transport proppants into the fracture and distribute them appropriately. Proppants must be selected which will not become imbedded in the fracture face or crush when subjected to the forces imposed by fracture closure. Recent evidence suggests that the currently available proppants are not being deposited as designed (resulting in shorter effective fracture lengths), or they are crushing during cleanup and/or later in the life of the well.

Remote Lenses

A major technological challenge in the lenticular basins is the possibility of the fracture penetrating lenses that were not originally contacted by the well bore. There are two critical issues: whether a fracture extending beyond the initial lens will enter another lens in its path or will bypass the second lens; and if the second lens is penetrated, whether it and the intervening shale can be effectively propped.

Fracture Azimuth and Lens Orientation

Knowing the compass orientation (azimuth) of the fracture is important in all tight formations. In blanket-type sands, it is necessary to determine well locations for optimal recovery. In lenticular formations, fracture azimuth relative to dominant lens orientation is critical. Long fractures perpendicular to narrow lenses (unless they encounter remote lenses) are wasted once the fractures leave the reservoir. Long fractures parallel to the lens, however, can produce at high initial rates. Although advances in measuring fracture azimuth have been made, substantial improvements are still needed.

Well Spacing

In current practice, one to four wells are typically located on every 640 acres in tight formations. In blanket sands, this usually puts all the pay into contact with a well bore. However, unless permeability is on the order of 0.5 md or greater, drainage will be incomplete or too slow for economic development. Such spacings in tight, lenticular basins are even less effective. Even with more than four wells per 640 acres, only a portion of the discontinuous lenticular lenses may be contacted. Drilling at closer spacing would increase the gas recovery per acre; closer spacing would result in considerably more of the lenticular reservoirs being contacted.

Formation Damage

Fracture fluids and/or proppants may interact with the reservoir rock to reduce formation permeability. These interactions may be chemical or physical in nature (e.g., the swelling of clays in the reservoir due to contact with water). Interactions may also be mechanical (e.g., the dislodging of microscopic particles from the proppants or from the reservoir). Either of these has the effect of blocking or reducing the pore throats through which the gas must flow, thus reducing the already low permeability.

Formation Water

In most cases, formation water is little more than a nuisance once the fracture has expelled the fracturing fluids. In some cases, formation water or water invasion during fracturing can significantly impair gas permeability at the fracture face. Technology is needed to "dewater" the reservoir in these cases. The use of foams or gases in the fracturing fluids and the injection of dry gas have been suggested.

Summary of Recovery and Evaluation Capabilities and Needs

Limited ability to determine fracture geometry severely restricts the ability to predict performance or to develop improved means to control performance. The industry's current response to these problems is to design and perform MHF treatments to the best

of its ability with very limited information. This approach can often result in excessive costs, incomplete drainage, or the reduced economic attractiveness of the resource.

Current methods of ascertaining geometry are limited. Temperature logs and tracer tests can show fracture height very near the well bore, but no measures are available to measure height away from the well bore. Moreover, no techniques for direct measurement of fracture width or length currently exist. Parametric analysis of production test data by computer reservoir simulators remains the only means of interpreting the conductivity and length of a fracture. Unfortunately, this approach produces a large number of viable interpretations and requires long production and pressure testing. A fracture designed for 2,000 feet, for example, might perform like one of 1,000 feet for several possible reasons: because excessive vertical growth reduced the actual length, because the fluid failed to carry the proppant beyond 1,000 feet, because of low conductivity in the fracture, or because of formation damage all along the fracture.

Past research and development has been limited to relatively low risk, evolutionary improvements. It is severely limited by inadequate reservoir data. And discouraging results, especially in the lenticular sands, have caused producers to adopt a "go-slow" posture.

Improving the economic attractiveness of the tight sands depends on increasing the reliability and efficiency of massive hydraulic fracturing relative to the cost of its application. The key elements for accomplishing these are discussed in the following sections.

DEEP (15,000+ FOOT) GAS DEVELOPMENT

This study does not include any potential gas resources in basins at depths of greater than 15,000 feet. Gas production 15,000 feet deep has been deregulated by the FERC. However, it is recognized that there are probably very significant resources of tight gas in the deep Rocky Mountain basins as well as gas in the deep Anadarko, Arkoma, and western Gulf basins.

In the Rocky Mountains, reservoirs of Cretaceous and Tertiary age have the best potential for yielding gas from tight reservoirs. With the exception of drilling in the Altamont oil field of the Uinta basin, very few wells have penetrated Tertiary and Cretaceous rocks below 15,000 feet.

However, those few wells that have penetrated Cretaceous and Tertiary strata below these depths have almost always yielded excellent stores of gas and commonly have tested small volumes of free gas on drillstem tests. The U.S. Geological Survey is currently studying cores from a few isolated deep dry holes in the

Rocky Mountains in an attempt to evaluate deep reservoir characteristics and provide data that may aid development of improved recovery technology. The USGS will then make an assessment of deep gas resources.

According to the USGS, those basins with the best deep tight gas potential in Tertiary and Cretaceous sandstones include the Wind River, Washakie, Great Divide, Green River (including Hoback), Bighorn, Hanna, and Uinta. Though a few presently commercial reservoirs have been encountered in the deep basins, completion attempts have been generally unsuccessful. Proppant crushing is one of the causes of some of these unsuccessful completions. The U.S. Department of Energy is researching the applicability of high strength sintered bauxite and other materials as proppants for deep frac jobs.

Usually these Cretaceous and Tertiary gas reservoirs are overpressured. Current work by the USGS has proposed that the active generation of gas is the cause of this overpressuring. As more deep wells are drilled and tested, this resource can be better defined.

Figure 40 illustrates the relationship between price and depth for the deep Mesaverde formation. Curves are shown for Mesaverde alone and in combination with another formation. Economics of developing deep reservoirs are improved when combined with other formations. This figure includes only gas above 15,000 feet in the 12 appraised basins. The large amount that lies deeper in the basins is omitted from the figure. It appears that the gas below 15,000 feet could be economically produced at prices above $7.00/ MCF if a second, more shallow producing formation is suitable for a combination well.

RESEARCH REQUIREMENTS

Enhancing technology for the development and recovery from tight gas formations will require advancements in many specific disciplines of research. In addition, it will be necessary to combine the knowledge from a wide variety of disciplines to optimize the rate of advancement on the learning curve. The problems and needs associated with tight gas reservoirs have been identified and discussed in preceding portions of this chapter as well as in many of the previous chapters. Topics and projects categorized by disciplines which have a high potential for addressing specific requirements are listed in Appendix H, "Research Topics and Programs." This appendix contains a suggested comprehensive program approach for conducting and organizing the specific research to accelerate learning, integrate theory into practice, and transfer the technology for application.

The Department of Energy's research and development program for enhanced gas recovery includes work on western tight gas reservoirs. A DOE report entitled "Gas Resources RD&D Plan" lists the research needs in tight formations that are the focus of the DOE program.

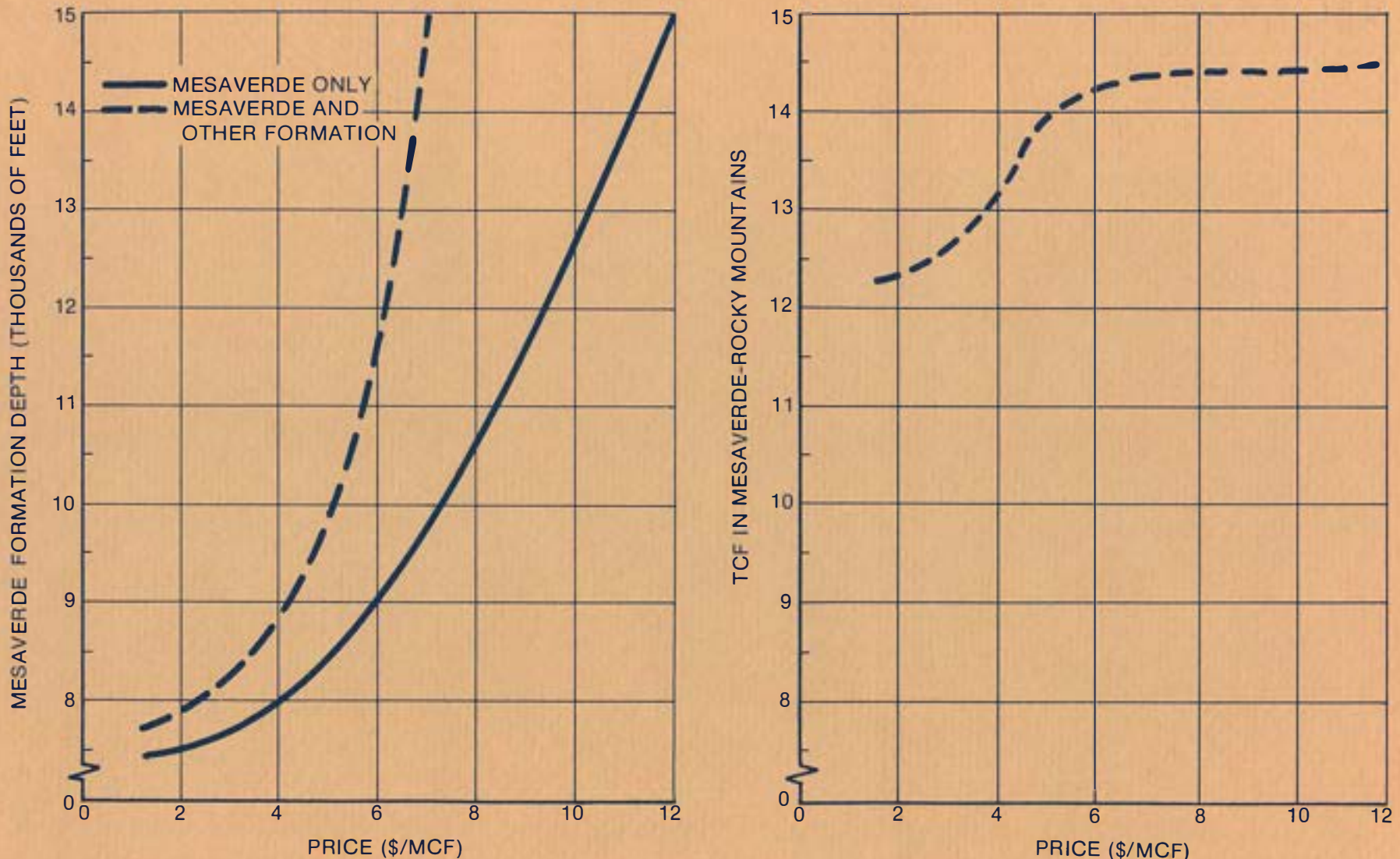


Figure 40. Relationship Between Price and Depth for the Mesaverde Formation.

BENEFITS, RESEARCH COST, AND RESEARCH TIMING REQUIRED TO ACHIEVE ADVANCED TECHNOLOGY

The discussions in previous sections of this chapter address the research needed to bring the tight formation gas technology from the base case to the advanced case. The benefits of moving from the base to the advanced case, in both the area of achieving additional gas resources throughout the United States as well as providing economic incentives, are colossal. However, the move will also require a significant investment in research time, manpower, and dollars from a wide spectrum of sciences and technologies associated with the industry. To achieve the results associated with the advanced case scenario will require a significant amount of concentrated research effort over the next 10 to 15 years. Table 92 depicts a schedule of research investment dollars. It covers the comprehensive research program outlined in Appendix H:

- Evaluation
- Resource and site characterization
- Research, instrumentation, and model development
- Production technology development.

TABLE 92

Research Expenditures to Achieve
Advanced Technology Case
(Millions of Dollars)

Year	Evaluation Programs	Resource and Site Characterization Programs	Research, Instrumentation and Modelling Programs	Production Technology Development Programs	Total
1	2	4	6	3	15
2	4	10	12	4	30
3	8	16	24	12	60
4	15	30	40	20	105
5	20	40	60	60	180
6	20	40	60	90	210
7	15	30	60	105	210
8	10	15	60	95	180
9	4	10	60	76	150
10	2	5	60	68	135
11	-	-	30	45	75
12	-	-	20	40	60
13	-	-	8	37	45
14	-	-	-	30	30
15	-	-	-	15	15
TOTAL	100	200	500	700	1,500

Present Worth
Discounted at 15% - 570

Specific items discussed previously in "Potential Technology Research Needs for Tight Gas Reservoirs" and the section in Appendix H entitled "Specific Potential Areas and Topics to Enhance Tight Gas Formation Development and Recovery" are addressed implicitly under these four relevant programs. As can be seen in Table 92, a research budget on the order of $1.5 billion is scheduled over a 15-year period. Approximately 85 percent of this is budgeted during the first 10 years. It will take approximately five years to develop each of the program sections into a full-scale research effort. A significant portion of the research dollar has been budgeted for production technology development programs which involve field applications or field research programs.

The research efforts here will require a significant amount of input from supplemental technologies. One example would be the requirement for the development of fracturing fluids which would involve many of the basic chemical industries which may not be currently associated directly with the petroleum industry. As the technology increases in sophistication, it is projected that basic physics and chemical sciences will become more and more involved, as will the electronics and instrumentation industry.

Some perspective of the economics involved can be seen in Figure 41. The solid line shows the cumulative cash flow that results from the bringing on of advanced technology. Over a 40-year period, approximately $100 billion additional revenue will accumulate as a result of the advanced technology. This discounts back to a net present worth on the order of $5.4 billion. The broken line shows a cash position of the research investment cost. The $1.5 billion spent over the 15-year period has a discounted net present worth at 15 percent of $570 million, which is approximately one tenth the net present worth of revenue generated.[1] If the probability of research success is 75-85 percent, the payout for the research investment will be achieved in approximately ten years. After payout, the earning rate will be approximately 20-25 percent for a 10-year period and will gradually decline thereafter. If probabilities of research success are on the order of 40-50 percent, the payout time will be increased to approximately 12 years and the rate of return for the 10-year period following payout will be reduced to approximately 15-20 percent.[2]

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[1]This figure indicates that the research investment will be recovered in about nine years (undiscounted).

[2]A very pessimistic projection of 10 percent success would only increase the payout time to 18 years.

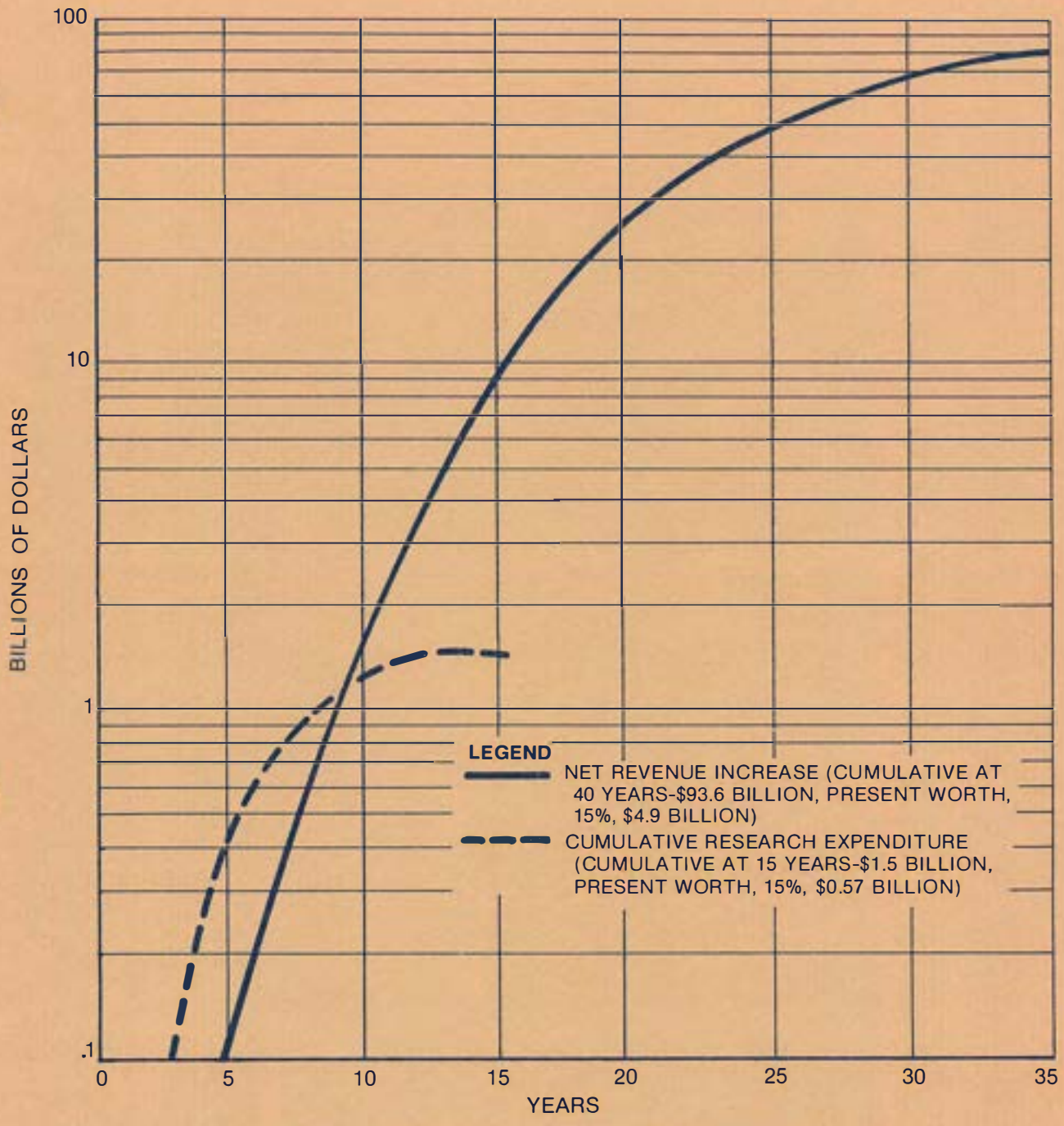


Figure 41. Cumulative Net Revenue Increase Resulting from Advanced Case Technology.

Chapter Nine

COMPARISON WITH OTHER STUDIES

A paucity of studies and the differences in the areas, formations, and areal extent of the basins which have been studied preclude an effective and accurate comparison of this study with previous ones. Actually, only two previous studies are recent and inclusive enough to allow a comparison: Enhanced Recovery of Unconventional Gas, 1978, by Lewin and Associates, Inc., and Nonconventional Natural Gas Resources, 1978, a National Gas Survey performed for the U.S. Department of Energy. Other studies that did not use similar methods for estimating were excluded from this comparison.

Table 93 illustrates the square miles (sections) encompassed in different areas by the three studies mentioned. The National Gas Survey report is not as extensive as the Lewin and NPC reports and makes no attempt to indicate recoverable gas resources. The Lewin and NPC reports more nearly cover the same areas even though the amount of area covered is variable. The National Gas Survey, except for the Northern Great Plains/Williston region, indicates much higher gas in place than the other studies.

The Lewin recoverable gas estimates are for the 13 basins they evaluated, while the NPC estimates are for 12 appraised basins and the 101 extrapolated basins in the lower 48 states. The totals are compared in Table 94. These relationships between price and technology are more readily compared in graph form in Figure 42.

Another kind of comparison may be made between the estimated percentage of gas recovered by the NPC and Lewin studies.

The National Gas Survey study considered economics but did not provide a relationship between gas price and total recoverable reserves for their basins. The Lewin report does provide such a relationship and it can be roughly compared with the NPC estimates. The first step is to inflate the Lewin prices (and economics) to the January 1, 1979, dollars used in the NPC economics. The Lewin prices in 1977 dollars were adjusted to January 1, 1979, dollars by the IPAA price index for drilling and equipping wells:

Mid-1977 Dollar Prices	January 1, 1979, Dollar Prices
$1.75/MCF	$2.12/MCF
$3.00/MCF	$3.64/MCF
$4.50/MCF	$5.45/MCF

Lewin estimated the potential recoverable gas at the three prices above and for two levels of technology. The base and advanced technology for the two reports differ somewhat, reflecting increasing technical optimism of engineers two years later.

This estimate is best made for the 13 basins studied in detail by Lewin and the 12 basins studied in detail by the NPC. Eleven of the same basins were studied by both groups.

TABLE 93

Comparison of Studies

Basin	National Gas Survey					Lewin Report					NPC Report				
	Potentially Productive Areas (Sq. Miles)	Gas In Place (TCF)	Gas In Place (BCF/Sec.)	Max. Rec. Gas (TCF)	Max. Rec. Gas (BCF/Sec.)	Potentially Productive Areas (Sq. Miles)	Gas In Place (TCF)	Gas In Place (BCF/Sec.)	Max. Rec. Gas (TCF)	Max. Rec. Gas (BCF/Sec.)	Potentially Productive Areas (Sq. Miles)	Gas In Place (TCF)	Gas In Place (BCF/Sec.)	Max. Rec. Gas (TCF)	Max. Rec. Gas (BCF/Sec.)
Northern Great Plains/Williston	32,500	130	4	--	--	24,080	74	3.0	35	1.4	32,730	148	4.2	100	3.0
Green River	1,800	240	132	--	--	870	91	104.6	36	41.3	8,938	136	15.2	82	9.2
Wind River	--	--	--	--	--	465	3	6.5	1	2.2	2,280	34	14.9	23	10.0
Uinta	515	150	290	--	--	996	50	50.2	18	18.0	1,184	21	17.7	15	12.7
Piceance	1,090	210	192	--	--	855	36	42.1	12	14.0	3,144	49	15.4	33	10.4
Denver	--	--	--	--	--	2,591	19	7.3	13	5.0	1,600	13	6.9	8	5.0
Big Horn	--	--	--	--	--	761	24	31.5	8	10.5	--	--	--	--	--
San Juan	1,800	63	35	--	--	830	15	18.0	12	14.5	1,188	3	2.5	2	1.7
Val Verde Ozona-Senora	--	--	--	--	--	1,960	24	12.2	16	8.1	500	5	10.0	3	6.0
Edwards Lime	--	--	--	--	--	--	--	--	--	--	450	14	31.1	9	20.0
Cotton Valley Sweet	--	--	--	--	--	5,127	53	10.3	40	7.8	1,027	22	21.4	13	12.6
Cotton Valley Sour	--	--	--	--	--	1,211	14	11.6	10	8.2	--	--	--	--	--
	37,705					39,746					53,041				

TABLE 94

Lewin vs. NPC Estimates of Recoverable Gas
(TCF)

Lewin 13 Basins

January 1, 1979, Price	$2.12	$3.64	$5.45
Base Technology	69.7	100.3	107.5
Advanced Technology	149.3	181.5	187.7

NPC

January 1, 1979, Price	$2.50		$3.50		$5.00		$9.00	
Number of Basins	12	113	12	113	12	113	12	113
Base Case	97	192	137		165	365	188	403
Advanced Case	142	331	192		231	503	271	574

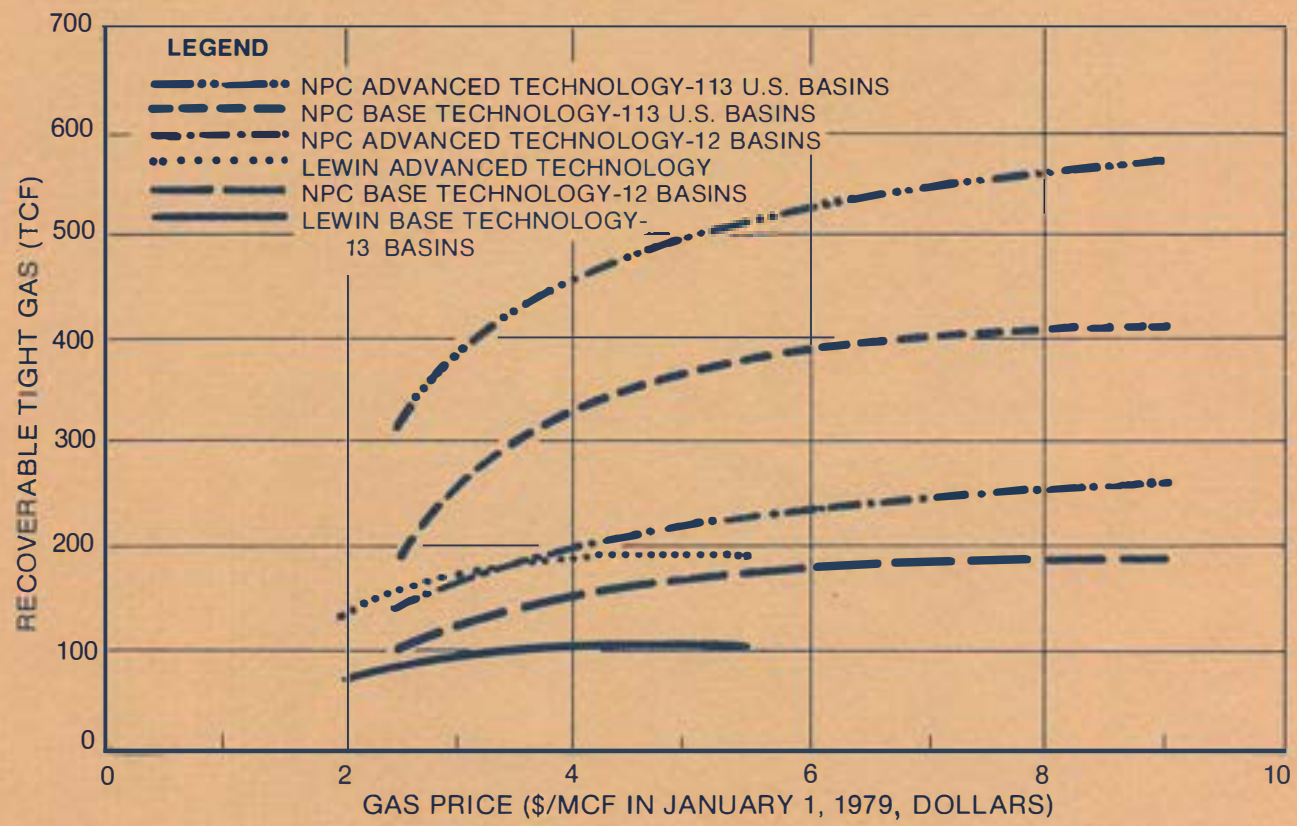


Figure 42. Total Tight Gas Potentially Recoverable—Comparison of NPC and Lewin Estimates.

The percentage recovery as affected by price and technology is compared in Figure 43. There is good agreement for the base case. The advanced case is quite different. Lewin expected percentage recoveries 15 to 30 percent greater than the NPC did for advanced technology. The NPC discounted recovery factors substantially to take into account poor quality portions of producing fields. The NPC geologists considered about 33 percent more sections than did Lewin. These additional sections often represented lower quality reservoir rock, and corresponding lower recoveries were calculated.

All of these reports carry the same message. The tight gas resource is very large. It can be produced at world energy prices and even more of it can be produced if technology can be improved. This is the third report on this subject. The FERC tight gas incentive price program makes it possible to start exploration in 1981, and price decontrol in 1985-1987 should encourage more drilling. Development of this gas resource can strengthen our country. Geologists should study the economic potential of the individual basins assessed in Part II of this report and consider tight gas plays.

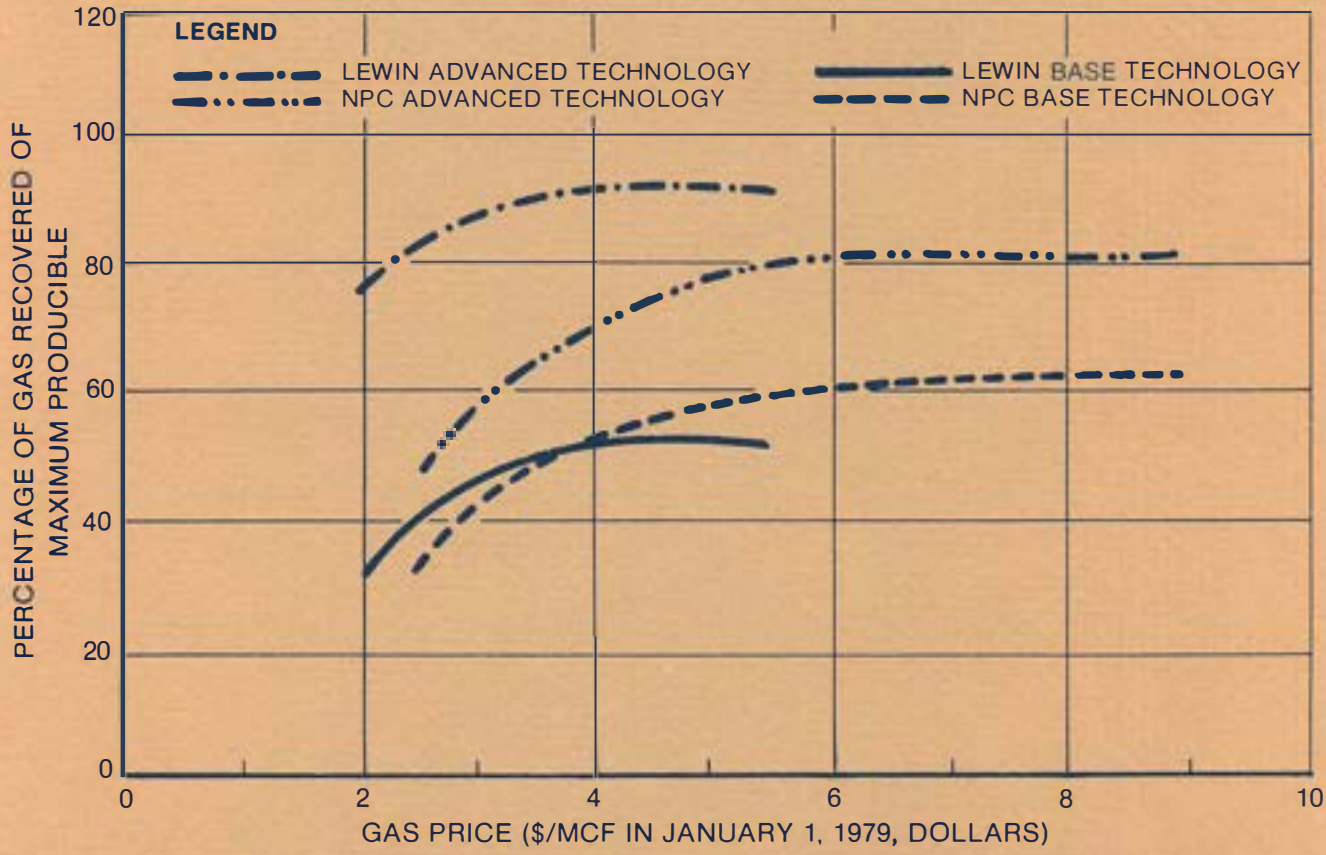


Figure 43. Percentage of Gas Recovery from Basins Studied in Detail by Lewin and NPC.

APPENDICES

APPENDIX A

Request Letter
and
Description of the
National Petroleum Council

Department of Energy
Washington, D.C. 20585

June 20, 1978

Dear Mr. Chandler:

An objective of the energy supply initiatives of the President's energy policy is to promote domestic energy production from unconventional sources as well as from conventional sources. One of the areas to be encouraged is the recovery of natural gas from unconventional sources.

In the past, the National Petroleum Council has provided the Department of the Interior with appraisals on the extent and recovery of the Nation's oil and gas resources through such studies as Future Petroleum Provinces, U. S. Energy Outlook, Ocean Petroleum Resources, and Enhanced Oil Recovery.

Therefore, the National Petroleum Council is requested to prepare, as an early and important part of its new relationship with the Department of Energy, a study on unconventional sources of natural gas to include deep geopressured zones, Devonian shale, tight gas sands, and coal seams. Your analysis should assess the resource base and the state-of-the-art of recovery technology. Additionally, your appraisal should include the outlook for costs and recovery of unconventional gas and should consider how Government policy can improve the outlook.

For the purpose of this study, I will designate the Deputy Assistant Secretary for Policy and Evaluation to represent me and to provide the necessary coordination between the Department of Energy and the National Petroleum Council.

Sincerely,

James R. Schlesinger
Secretary

Mr. Collis P. Chandler, Jr.
Chairman, National Petroleum
Council
1625 K Street, N. W.
Washington, D.C. 20006

DESCRIPTION OF THE NATIONAL PETROLEUM COUNCIL

In May 1946, the President stated in a letter to the Secretary of the Interior that he had been impressed by the contribution made through government/industry cooperation to the success of the World War II petroleum program. He felt that it would be beneficial if this close relationship were to be continued and suggested that the Secretary of the Interior establish an industry organization to advise the Secretary on oil and natural gas matters.

Pursuant to this request, Interior Secretary J. A. Krug established the National Petroleum Council (NPC) on June 18, 1946. In October 1977, the Department of Energy was established and the Council's functions were transferred to the new department.

The purpose of the NPC is solely to advise, inform, and make recommendations to the Secretary of Energy on any matter, requested by him, relating to petroleum or the petroleum industry. The Council is subject to the provisions of the Federal Advisory Committee Act of 1972.

Matters which the Secretary of Energy would like to have considered by the Council are submitted as a request in the form of a letter outlining the nature and scope of the study. The request is then referred to the NPC Agenda Committee, which makes a recommendation to the Council. The Council reserves the right to decide whether or not it will consider any matter referred to it.

Examples of recent major studies undertaken by the NPC at the request of the Department of the Interior and the Department of Energy include:

- Petroleum Resources Under the Ocean Floor (1969, 1971)
  Law of the Sea (1973)
  Ocean Petroleum Resources (1974, 1975)
- Environmental Conservation -- The Oil and Gas Industries (1971, 1972)
- U.S. Energy Outlook (1971, 1972)
- Emergency Preparedness for Interruption of Petroleum Imports into the United States (1973, 1974)
- Petroleum Storage for National Security (1975)
- Potential for Energy Conservation in the United States: 1974-1978 (1974)
  Potential for Energy Conservation in the United States: 1979-1985 (1975)
- Enhanced Oil Recovery (1976)

- Materials and Manpower Requirements (1979)
- Petroleum Storage & Transportation Capacities (1979)
- Refinery Flexibility (1980).

The NPC does not concern itself with trade practices, nor does it engage in any of the usual trade association activities.

Members of the National Petroleum Council are appointed by the Secretary of Energy and represent all segments of petroleum interests. The NPC is headed by a Chairman and a Vice Chairman who are elected by the Council. The Council is supported entirely by voluntary contributions from its members.

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APPENDIX B

Study Group Rosters

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Mobil Research &
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Dr. J. P. Brashear, Principal
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Amoco Production Company

John S. Conway
Petroleum Engineer
U.S. Department of Energy

T. D. Cook
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Shell Oil Company

Sandra J. Dougherty
Associate Computer Analyst
Amoco Production

Lloyd E. Elkins
Petroleum Consultant
Lewin & Associates, Inc.

John H. Evans
Senior Research Economist
Mobil Research &
Development Corporation

David C. Faecke
Senior Research Economist
Mobil Research &
Development Corporation

David V. Findley
Research Assistant
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APPENDIX C

Cumulative Gas Recovery and Average Gas Producing Rate Calculations

CUMULATIVE GAS RECOVERY AND AVERAGE GAS PRODUCING RATE CALCULATIONS

The method used to predict cumulative gas production and gas producing rates employed type curves developed from a computerized reservoir simulation model. The type curves apply to a wide variety of reservoir permeabilities, porosities, net pay values, pressures, temperatures, gas compositions, and fracture conductivities. However, different sets or type curves are required for different drainage boundary configurations. The type curves used to generate production rate and cumulative gas recovery are consistent with the reservoir/fracture system geometries described in Chapter Three (see Table 19). These are depicted in Figures C-1a through C-1d, which show the various fracture lengths and reservoir boundary configurations used for generating the base and advanced case production estimates. The configurations in Figure C-1 represent one quarter of a symmetric drainage pattern.

As shown in Figures C-2 through C-5, cumulative type curves of

$$G_{pD} = f\,(F_{cD}, t_{Dx_f}) \qquad (1)$$

where

G_{pD} = dimensionless cumulative gas production,

F_{cD} = dimensionless fracture flow capacity, and

t_{Dx_f} = dimensionless time

were developed to estimate gas recoveries and gas producing rates for each different set of reservoir properties included in this study.

Type curves are merely a display in graph form of the calculations generated from a finite-difference, computerized reservoir simulator. With the coordinates

$$G_pD = \frac{9000\ T\ G_p}{h\ \phi\ \mu\ c_t\ x_f^2\ \Delta[m(p)]} \qquad (2)$$

$$t_{Dx_f} = \frac{2.634 \cdot 10^{-4}\ kt}{\phi\ \mu\ c_t\ x_f^2} \qquad (3)$$

and

$$F_{cD} = \frac{k_f w_f}{k\ x_f} \qquad (4)$$

the curves represent a normalized composite which, in effect, applies to any combination of reservoir properties. Thus, one set of cumulative type curves can be used to calculate cumulative gas production and average gas producing rates for a variety of different reservoirs and reservoir conditions. The application of type

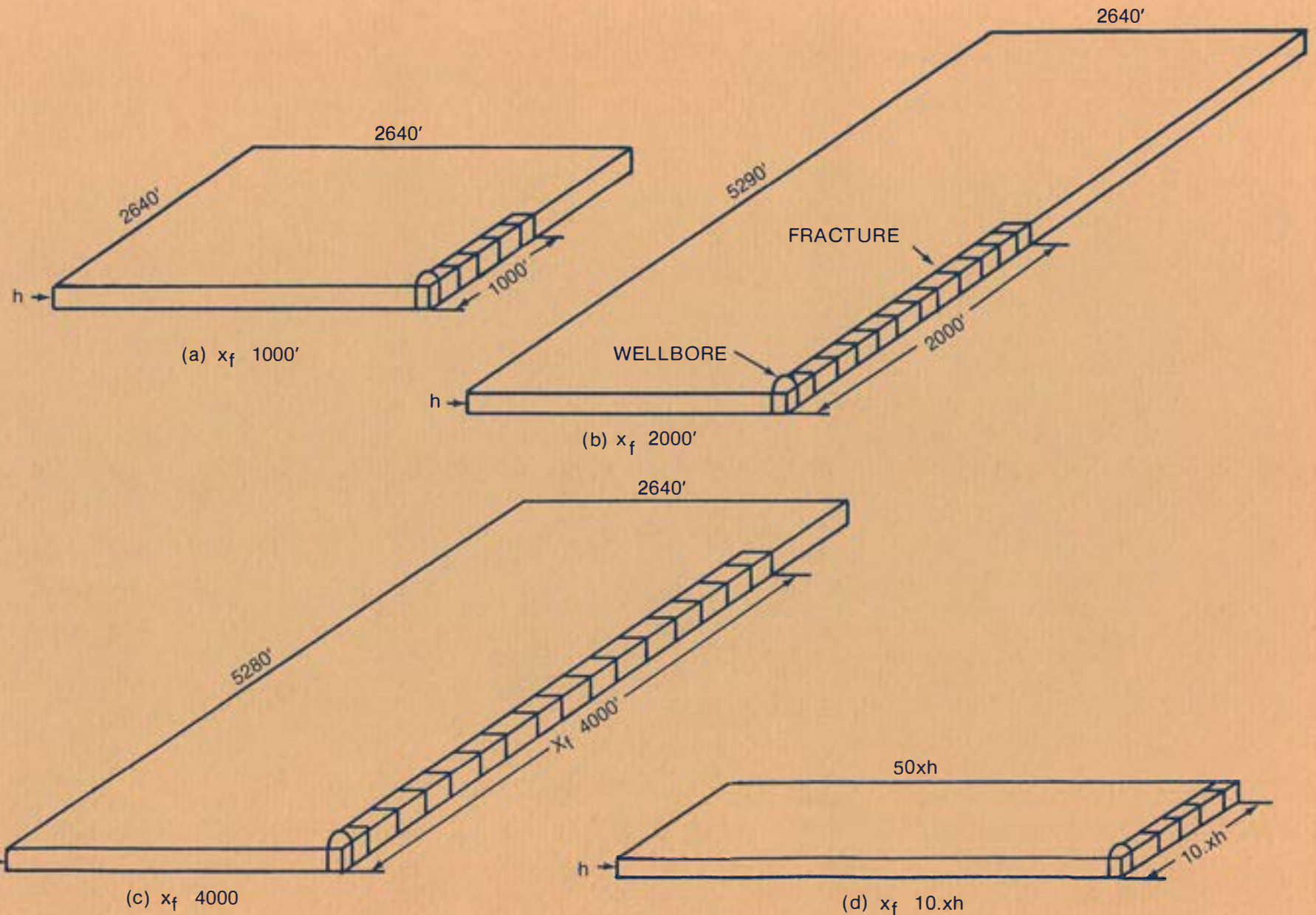


Figure C-1. Fracture Lengths and Reservoir Configurations Used for Generating the Base and Advanced Case Production Estimates.

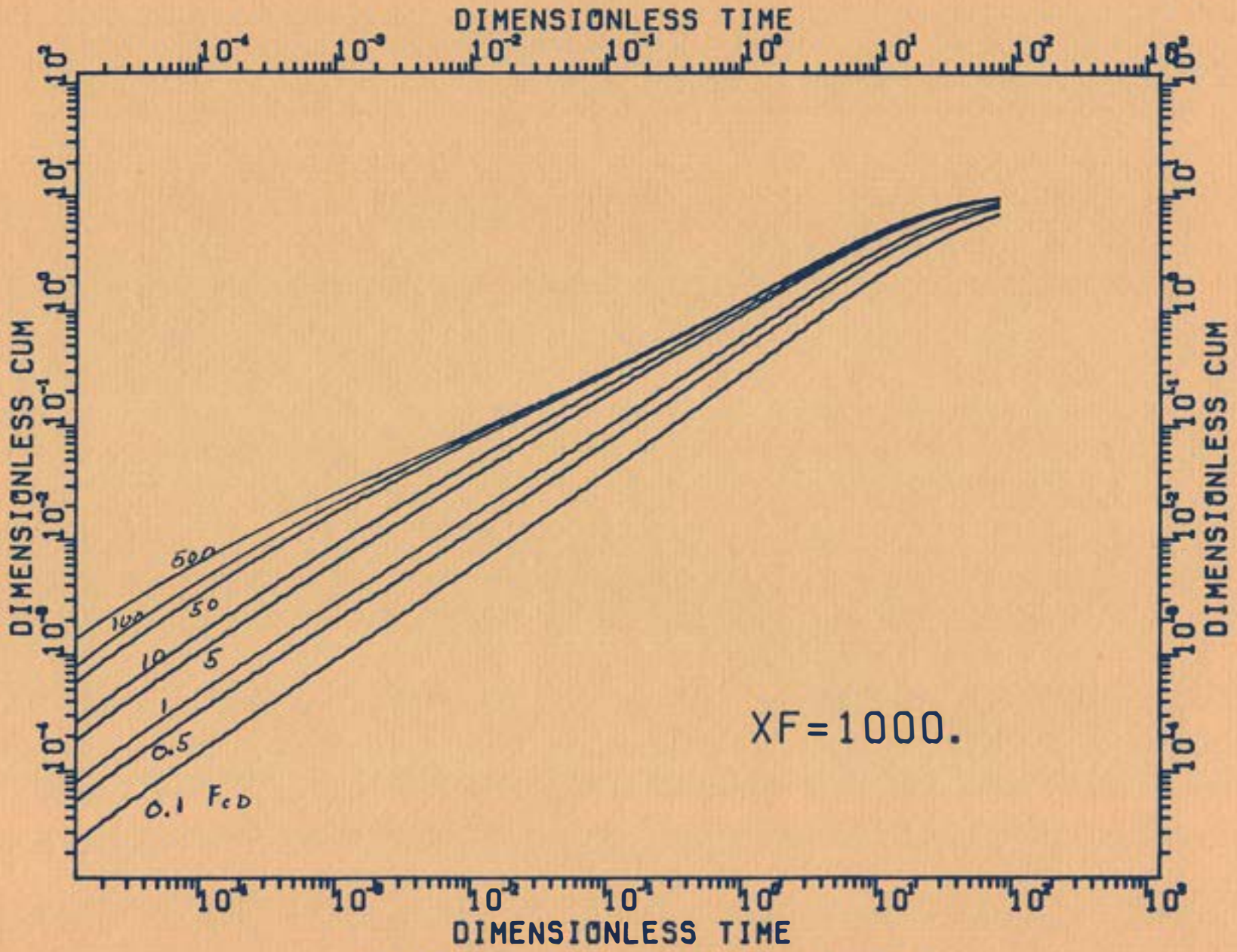


Figure C-2. Estimated Gas Recovery and Producing Rates.

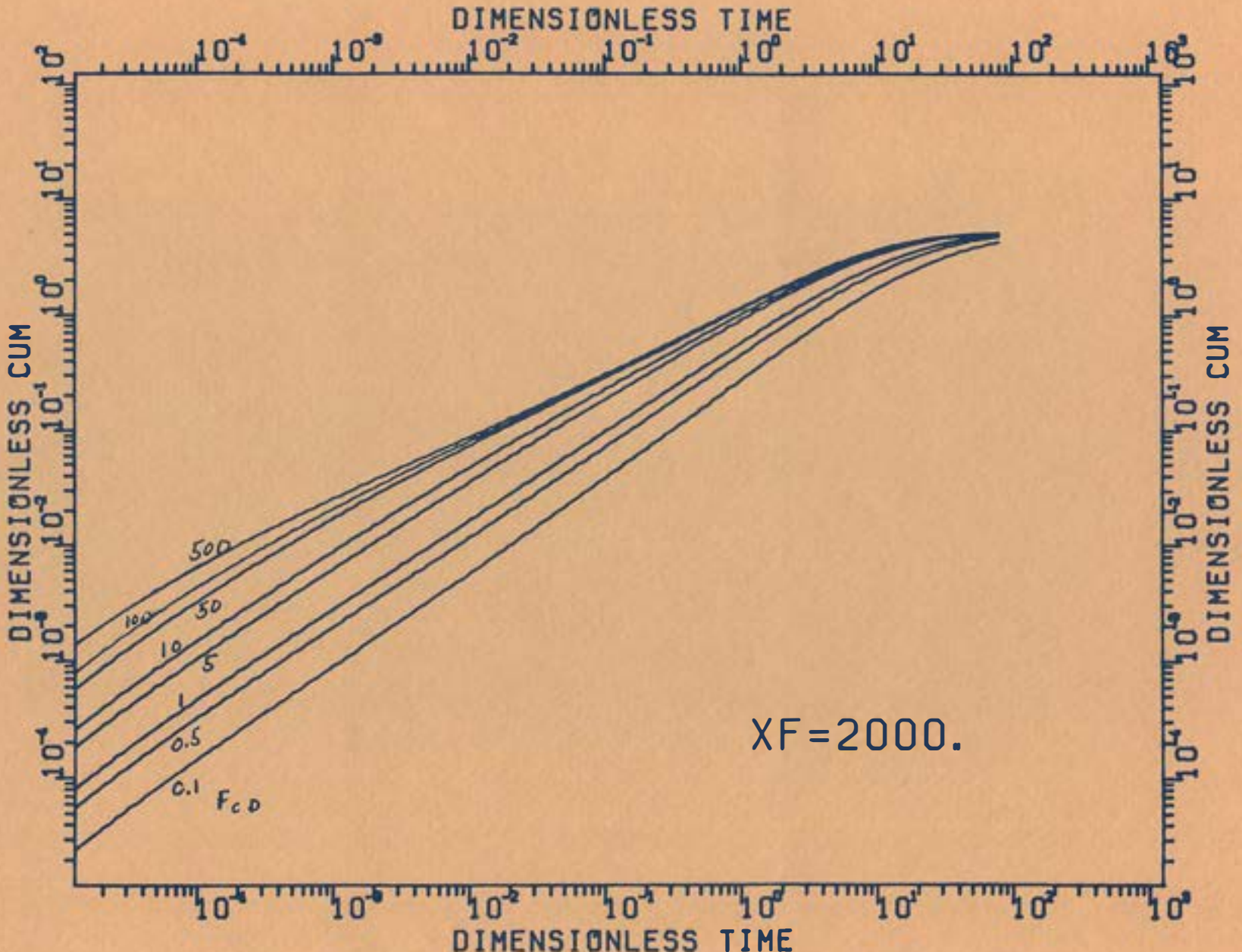


Figure C-3. Estimated Gas Recovery and Producing Rates.

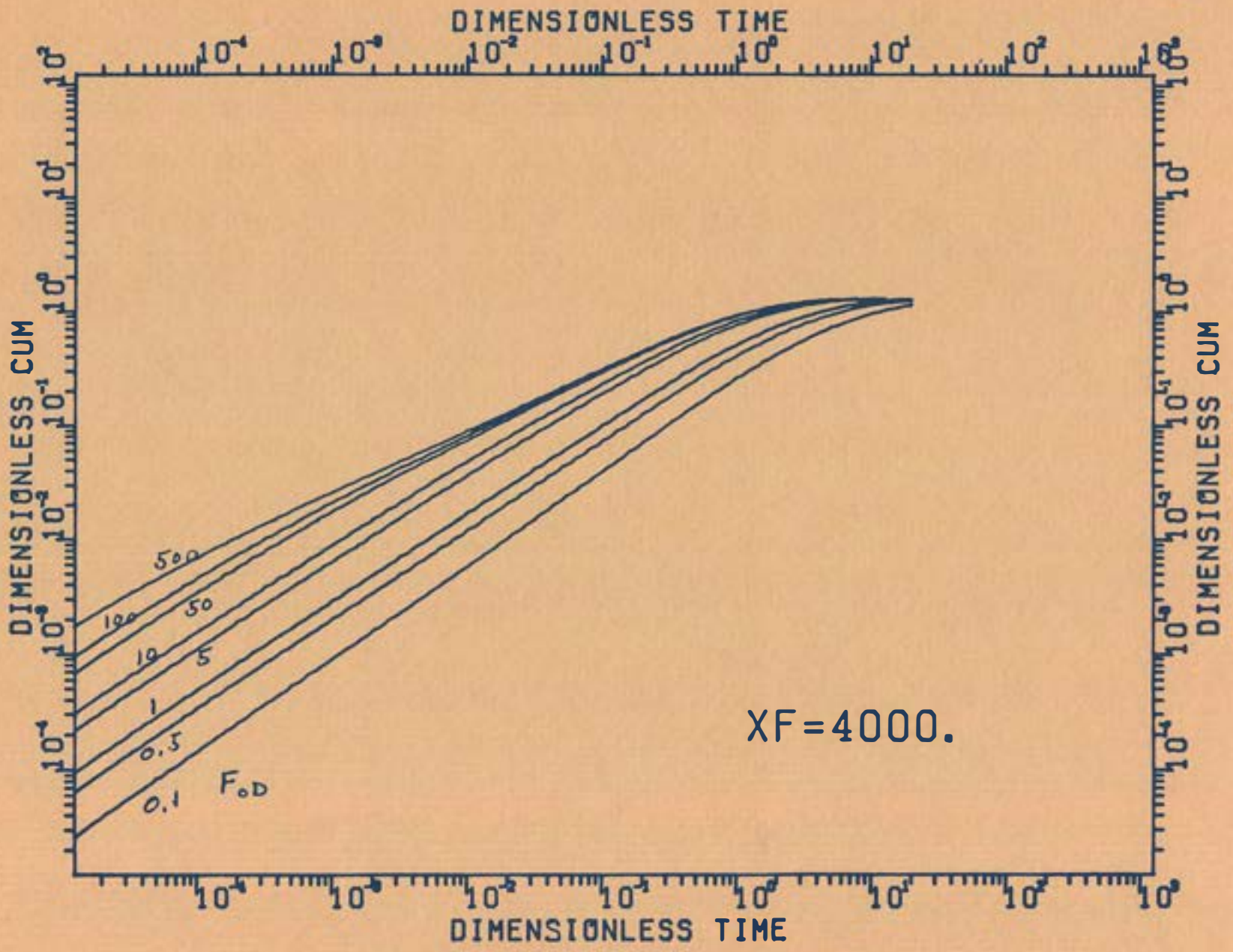


Figure C-4. Estimated Gas Recovery and Producing Rates.

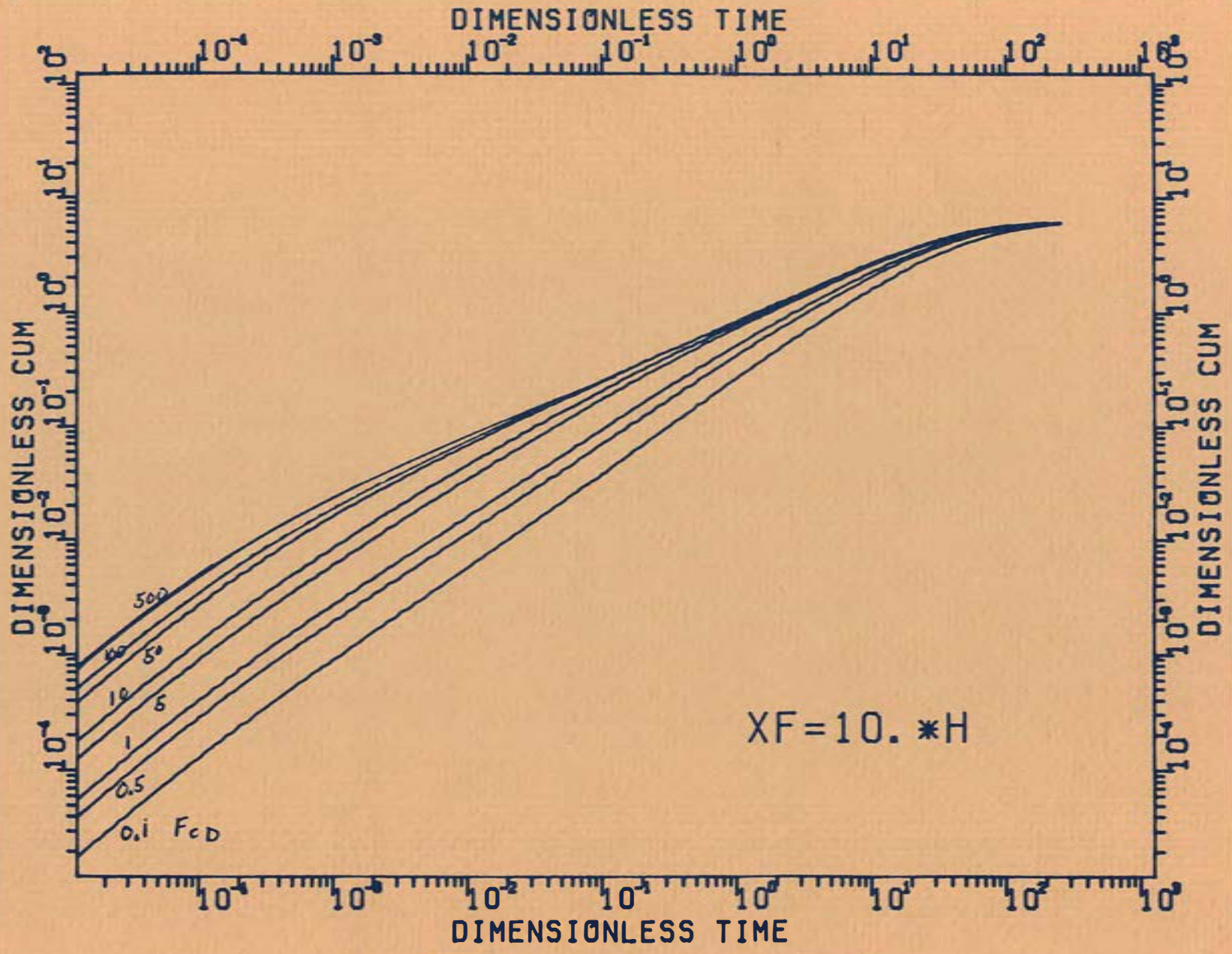


Figure C-5. Estimated Gas Recovery and Producing Rates.

curves is well documented and referenced by the industry for representing gas producing rate and cumulative recovery.

The type curves in Figure C-2 apply to a 640-acre, square drainage area with one centrally located well (Figure C-1a). This set applies for a single, vertical, finite-conductivity fracture which extends symmetrically 1,000 feet on either side of the well bore. This set was used for the blanket sand base case technology predictions. Figures C-3 and C-4 show the type curves used for the blanket sands advanced case 2,000-foot and 4,000-foot fractures. These curves apply for a rectangular shaped (2:1 length to width ratio) 1,280-acre drainage area (Figures C-1b and C-1c). Here the fracture runs parallel to the long side of the drainage pattern and contacts the entire vertical net pay interval.

Figure C-5 is for the lenticular sands. The type curves here are consistent with Figure C-1d, which depicts a fracture cutting across a lens with dimensions of height (h), width (20h), and length (100h).

The procedure used in each set of calculations is as follows:

1. Specify reservoir parameter values: permeability (k), porosity (ϕ), net pay (h), initial pressure (p_i), sandface flowing pressure (p_w), and temperature (T).

2. Specify a gas properties table at discrete points of pressure (p) and temperature (T): viscosity (μ), compressibility (c), real gas deviation factor (Z), and real gas potential [m(p)].

3. Specify fracture parameter values: fracture half-length (x_f-well bore to fracture tip), fracture conductivity ($k_f w_f$).

4. Select a set of desired real time values (t) at which corresponding cumulative production values (G_p) and average producing rates (q_{avg}) are desired (e.g., one year, two years, ...30 years).

5. Compute dimensionless times (t_{Dx_f}) for each desired real time value (t) (Equation 3) and the dimensionless fracture conductivity value (F_{cD}) (Equation 4).

6. Interpolate dimensionless cumulative production value (G_{pD}) value for each dimensionless time value (t_{Dx_f}) at the appropriate dimensionless fracture flow capacity (F_{cD}) from Figure C-1 for a 1,000-foot fracture length or from Figure C-2 for a 2,000-foot fracture length.

7. Use Equation 2 to back-calculate the real cumulative gas production values (G_p) from the interpolated dimensionless cumulative production values (G_{pD}) for each corresponding real time value (t) specified in Step 3.

This provides a set of cumulative production values (G_p) vs. real time (t) for the reservoir properties and fracture parameters specified in Steps 1, 2, and 3. Values of average daily production rate (q_{avg}) for any specific year are determined by subtracting the cumulative production at the end of the previous year from the cumulative production at the end of the specific year and dividing by 365.25 days.

Figures C-2 through C-5 were generated from a finite-difference gas reservoir simulator computer model using reservoir, gas, and fracture parameter values in the range of those reservoirs included in this study. A computer model program was developed to automatically perform the computations discussed in Steps 1 through 7 above. In all calculations, a gas with a gravity of 0.65 (air = 1.00) was considered typical for the reservoirs included in this study. The values for viscosity, fluid compressibility, gas compressibility factor, and real gas potential (functions of pressure and temperature) were computed for discrete pressures and temperatures and listed in tabular form. Linear interpolation and gas law equations were used to determine values of viscosity, compressibility, gas compressibility factor, and real gas potential for pressures and temperatures not listed in the table.

In the calculations for this study, as a matter of convention, the flowing sandface pressure (p_w) was chosen to be one tenth of the initial reservoir pressure (p_i) for any given reservoir. The above methods were found to provide accuracies within 10 percent of the values calculated using a finite-difference, computerized simulation model. The production rate for the first year was reduced by deleting the first 14 days' cumulative production to account for losses due to post-fracture treatment cleanup and testing.

Nomenclature:

A = drainage area of a fracture well

c = compressibility, 1/psi

c_t = total system compressibility, 1/psi

F_{cD} = dimensionless fracture flow capacity (see Equation 4)

h = formation thickness, ft

k = formation permeability, md

k_f = fracture permeability, md

$m(p)$ = real gas pseudo-pressure, psi^2/cp =

$$2 \int_{p_o}^{p} \frac{\tau \, d\tau}{\mu(\tau)\, z(\tau)}$$

$\Delta[m(p)]$ = difference in real gas pseudo-pressures, $psi^2/cp = m(p_i) - m(p_w)$

p = pressure, psi

p_i = initial pressure, psi

p_o = base pressure, psi

p_w = sandface flowing pressure, psi

G_p = cumulative gas production, MMCF

G_{pD} = dimensionless cumulative gas production (see Equation 2)

q = flow rate, stb/d or MCF/D

t = flowing time, hours

t_{Dx_f} = dimensionless time based on x_f (see Equation 3)

T = reservoir temperature, °F

w_f = fracture width, ft

x_f = fracture half-length, ft

Z = real gas deviation factor

μ = viscosity, cp

ϕ = formation porosity, fraction

APPENDIX D

Cost Estimates

ESTIMATION OF DRILLING COST

Drilling costs for wells can be obtained by either of the following two methods:

- Use of the Cost Equation: Table D-1
  - Select the appropriate region (first column) for the basin (second column) of interest.
  - Read the "slope" (fourth column) and "intercept" (fifth column).
  - Select the well depth being evaluated. Make certain this depth falls in the "depth range" (third column).
  - Use the following equation to calculate "1977" cost:

    $$\text{Cost (1977\$)} = e^{[\text{Intercept} + \text{Slope (depth in feet)}]}$$

  - Adjust costs to January 1, 1979 (1 1/2 years at 12 percent per year):

    $$\text{Cost (1979\$)} = 1.1872 \text{ Cost (1977\$)}$$

- Use of Graphs: Figures D-1 and D-2
  - Select the appropriate region (Table D-1, first column) for the basin (second column) of interest.
  - Select the figure for that region.
  - Select the well depth being evaluated.
  - Read the cost (1977$) from the appropriate figure for this depth.
  - Adjust costs to January 1, 1979 (1 1/2 years at 12 percent per year).

    $$\text{Cost (1979\$)} = 1.1872 \text{ Cost (1977\$)}.$$

BASIS AND PROCEDURES USED IN DEVELOPING DRILLING COST ESTIMATION METHOD

Source of Data

The Joint Association Survey has published costs of drilling and completion of gas wells that include all costs through the "Christmas tree." (The latest publication of the data was for

TABLE D-1

Drilling and Completion Cost Equation Coefficients -- 1977

Region	Basin	Depth Range	Slope	Intercept	R^2	Error
1. Colorado	Denver	1250-9999	.0002139	11.089932	.85449	1.1876
2. E. New Mexico	Raton	0-19999	.0002206	10.830232	.96221	1.1843
3. Montana	Northern Basin	0-3749	.0004148	10.048623	.85165	1.0874
	Williston					
4. Oklahoma-Arkansas	Arkoma-Ouachita	3750-9999	.0002203	10.867174	.95886	1.0944
5. Oklahoma-Texas 10	Anadarko	0-19999	.0002610	10.455285	.96561	1.2261
6. Wyoming-Utah	Big Horn	2500-4999	.0002691	11.011735	.96771	1.0340
	Wind River					
	Piceance	5000-14999	.0002335	11.252823	.95568	1.1200
	Greater Green River					
	Uintah					
	Wasatch					
	Snake River					
	Douglas Creek					
7. Texas 6-N. Louisiana	Cotton Valley	7500-12499	.0003038	10.393858	.99701	1.0138
8. Texas 7	Sonora	5000-9999	.0001914	10.831515	.99998	1.0007
9. Texas 9	Fort Worth	0-12499	.0004919	8.938533	.98306	1.0858
10. Texas 2,3,4	Edwards Lime	0-17499	.0002903	10.4716585	.95015	1.2382
11. W. New Mexico	San Juan	5000-9999	.0001999	11.060594	.99988	1.0012

Cost (1977 $) = $e^{[\text{Intercept} + \text{Slope (depth in ft.)}]}$

Adjust costs about 12% per year (1-1/2 years) to bring to 1/1/79.

Results based on 1977 JAS data - depths selected for basins.

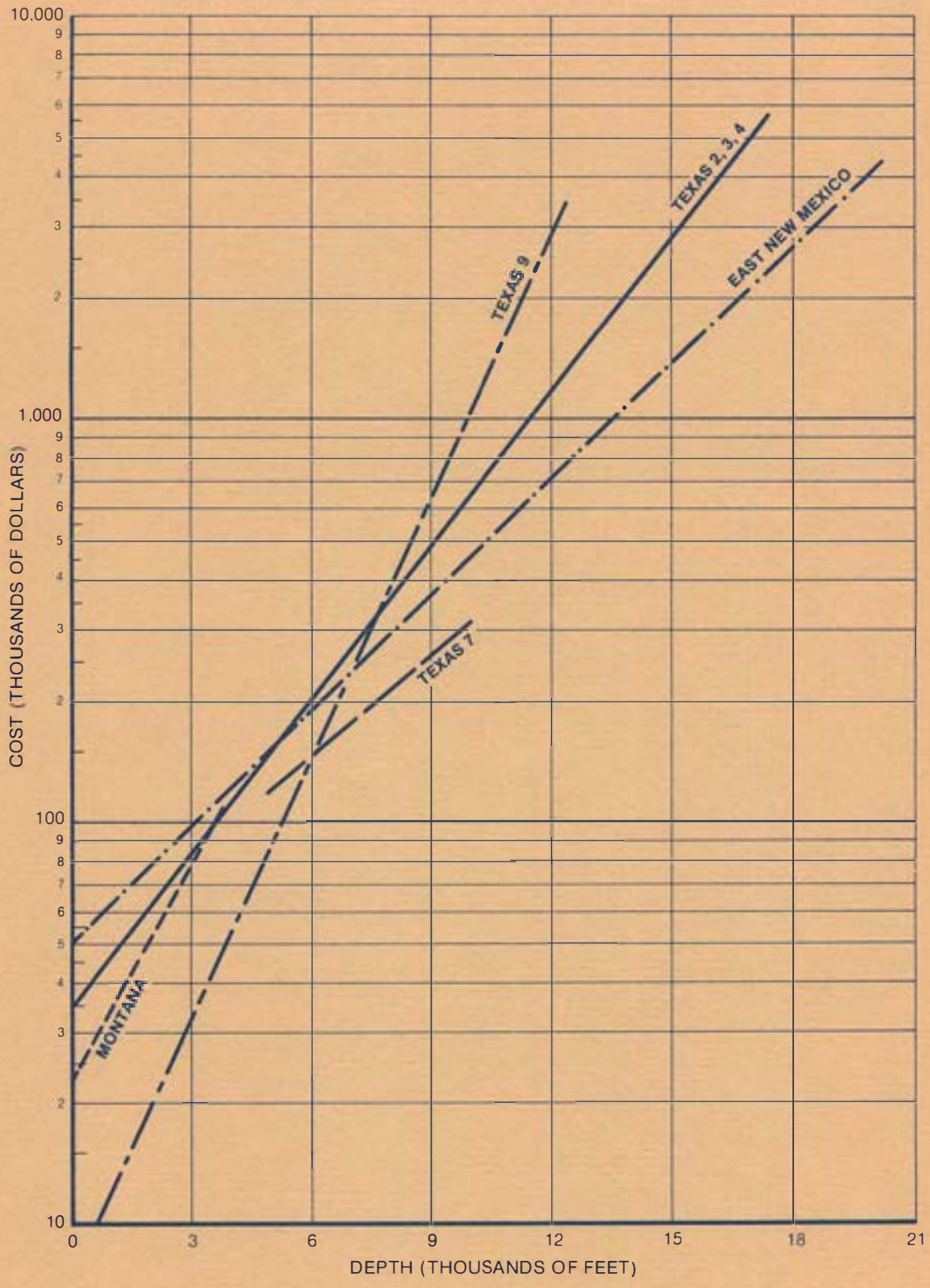


Figure D-1. Regional Drilling Cost Estimates.

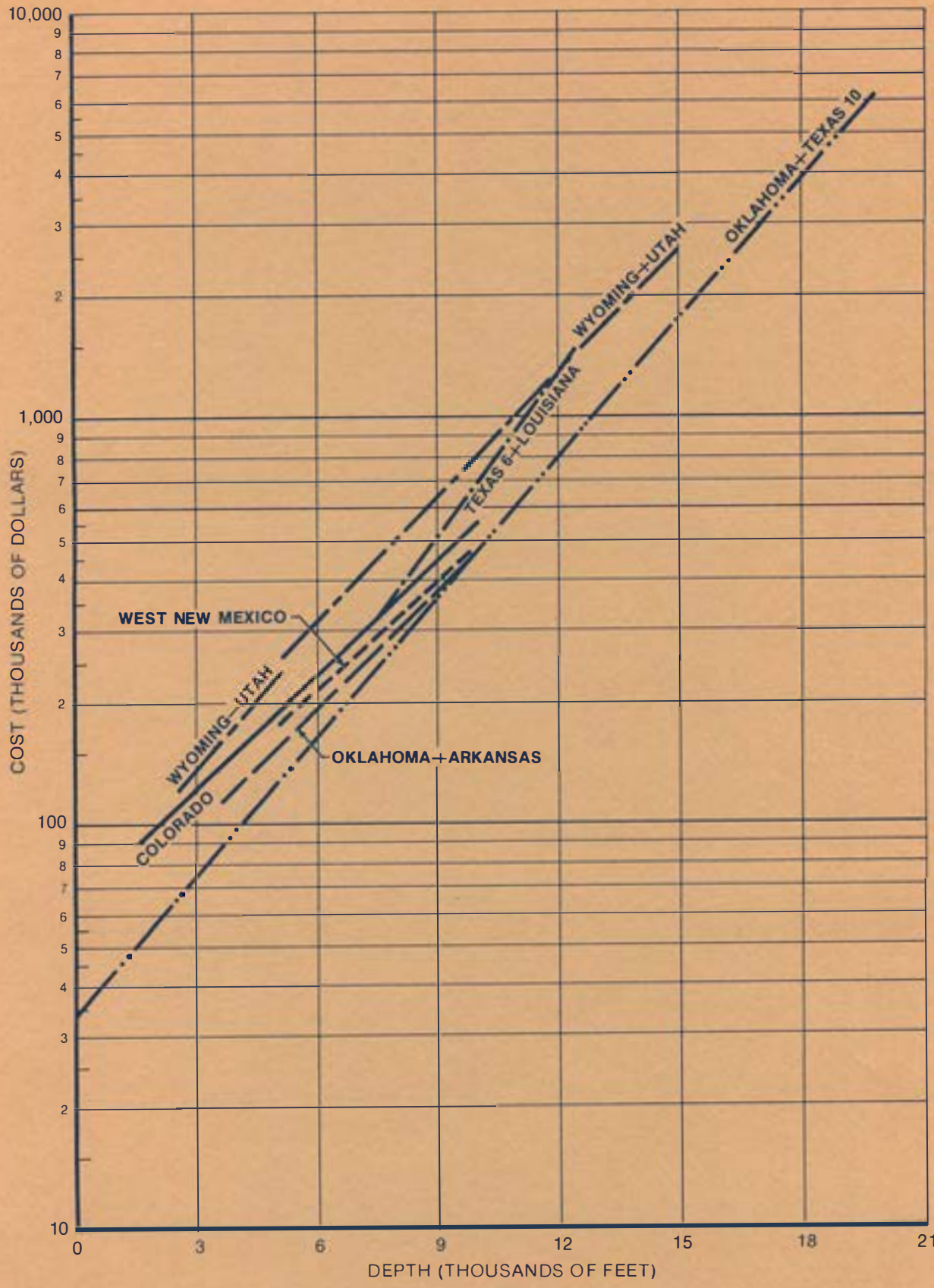


Figure D-2. Regional Drilling Cost Estimates.

1977.) The costs are reported by state (and substate district) and by depth. Table D-2 is an example of the 1977 JAS data (for Colorado). JAS instructions for cost are:

Report the total cost (tangible and intangible) of each well completed by you as operator in the survey year (whether actually drilled by you or drilled for you by contractors). The total of such costs should be reported even though you as operator had only a part of a working interest in the well. Do not report the cost of wells drilled by others in which you had a working interest regardless of the size of such interest. The costs to be reported are those associated with wells which were completed during the survey year and the dollar amount to be reported is the accumulated cost of such wells from the time locations were made until the wells were completed as productive wells or abandoned after drilling was terminated because they were nonproductive.

In general, the elements contributing to reported cost are the expenditures for drilling dry holes and productive wells and equipping new productive wells through the Christmas tree installation. More specifically these cost elements are the costs of labor, materials, supplies, water, fuels, power, and direct overhead (i.e., field, district, and regional), for such operations as site preparation, road building, erecting and dismantling derricks and drilling rigs, drilling hole, running and cementing casing, hauling materials, etc. Include the total cost of water, if purchased, or cost of water well, if drilled and chargeable to oil or gas well drilling operations. Well costs also include machinery and tool charges and rentals, and depreciation charges, where appropriate, for rigs and other equipment and facilities which will be used in drilling more than one well. Deduct the condition value of materials salvaged after use where appropriate.

Do not report the cost of lease equipment such as artificial lift equipment and downhole lift equipment, flow lines, flow tanks, separators, etc., that are required for production. Do not reduce reported costs by test well, bottom hole, or dry hole contributions.

For offshore wells, include costs of fixed platforms and islands. Where facilities serve more than one well, the costs should be allocated to each well on the basis of the operator's best current estimate of the ultimate number of wells that will use the facility. Also, include cost expirations (depreciation or amortization) for company-owned mobile platforms, barges, and tenders.

Treatment of JAS Data

Data for areas of interest (basins) were selected from the JAS data. These were various combinations of substate districts and states that best covered the basin being considered (See the first column, Table D-1).

Regression analysis of the data revealed that total drilling and completion costs fit relatively closely to a logarithmic function with well depth. The JAS gas well data were analyzed using

TABLE D-2

ESTIMATED COSTS OF DRILLING AND EQUIPPING WELLS, BY DEPTH INTERVALS • 1977

COLORADO

DEPTH INTERVAL (FEET)		TOTAL NUMBER OF WELLS, FOOTAGE DRILLED, AND COSTS				AVERAGE DEPTH AND COST PER WELL			
		OIL WELLS	GAS WELLS	DRY HOLES	TOTAL	OIL	GAS	DRY	TOTAL
0 - 1,249	WELLS	5	1	10	16				
	FOOTAGE	3,043	1,206	8,228	12,477	608	1,206	822	779
	COSTS $	146,064	49,832	287,022	482,918	29,212	49,832	28,702	30,182
1,250 - 2,499	WELLS	5	25	23	53				
	FOOTAGE	7,099	50,870	47,146	105,115	1,419	2,034	2,049	1,983
	COSTS $	348,184	1,673,656	750,665	2,772,505	69,636	66,946	32,637	52,311
2,500 - 3,749	WELLS	9	87	38	134				
	FOOTAGE	29,147	276,987	114,497	420,631	3,238	3,183	3,013	3,139
	COSTS $	919,408	11,601,725	2,213,347	14,734,480	102,156	133,353	58,245	109,958
3,750 - 4,999	WELLS	105	56	108	269				
	FOOTAGE	501,357	241,043	494,367	1,236,767	4,774	4,304	4,577	4,597
	COSTS $	12,190,806	11,567,585	6,723,104	30,481,495	116,102	206,564	62,250	113,314
5,000 - 7,499	WELLS	212	60	224	496				
	FOOTAGE	1,212,370	372,457	1,354,034	2,938,861	5,718	6,207	6,044	5,925
	COSTS $	41,809,321	14,985,973	18,482,042	75,277,336	197,213	249,766	82,509	151,768
7,500 - 9,999	WELLS	31	43	52	126				
	FOOTAGE	244,648	349,744	422,369	1,016,761	7,891	8,133	8,122	8,069
	COSTS $	6,162,676	14,055,993	8,355,983	28,574,652	198,796	326,883	160,691	226,782
10,000 - 12,499	WELLS			3	3				
	FOOTAGE			31,030	31,030	•	•	10,343	10,343
	COSTS $			1,644,523	1,644,523	•	•	548,174	548,174
12,500 - 14,999	WELLS								
	FOOTAGE					•	•	•	•
	COSTS $					•	•	•	•
15,000 - 17,499	WELLS			3	3				
	FOOTAGE			49,182	49,182	•	•	16,394	16,394
	COSTS $			9,112,659	9,112,659	•	•	3,037,553	3,037,553
17,500 - 19,999	WELLS		1		1				
	FOOTAGE		17,654		17,654	•	17,654	•	17,654
	COSTS $		9,923,313		9,923,313	•	9,923,313	•	9,923,313
20,000 & OVER	WELLS								
	FOOTAGE					•	•	•	•
	COSTS $					•	•	•	•
TOTAL WELLS		367	273	461	1,101				
TOTAL FOOTAGE		1,997,664	1,309,961	2,520,853	5,828,478	5,443	4,798	5,468	5,293
TOTAL COSTS $		61,576,459	63,858,077	47,569,345	173,003,881	167,783	233,912	103,187	157,133

the average footage and cost such as those shown in Table D-2, seventh column. The data were weighted to represent the number of wells in a given footage interval, as shown in the third column. Data covering only the footage range applicable to depths where tight gas basins are known to exist were analyzed. Figures D-1 and D-2 show the resulting best-fit lines. Table D-1 gives the slope and intercept for these lines as well as R^2 and "Error" which measures how well the data fit the assumed correlation.

ESTIMATION OF FRACTURE TREATMENT COST

To estimate the fracturing cost for a well:

- Estimate fracture height.
- Select fracture length.
- Read frac fluid volume required for this fracture height and length from either Figure D-3 for base case or Figures D-4 and D-5 for advanced case.
- Read basic cost of fracturing treatment for this volume from Figures D-6 and D-7.
- Adjust this basic cost for location (basin) and for depth of well by multiplying basic cost by the adjustment factors obtained from Table D-3 and Table D-4:

  $$\text{Frac Cost} = (\text{Basic Cost}_{\text{Fig D-6 or D-7}})\ (AF_{\text{Location}})(AF_{\text{Depth}})$$

- At 15,000 feet, bauxite must be used instead of sand and cost must be increased:

  $$\text{Frac Cost}_{\text{w/bauxite}} = \text{Frac Cost}_{\text{w/sand}} + (2)(\text{Frac Fluid Vol})\ (0.75)$$

ASSUMPTIONS AND PROCEDURES USED IN DEVELOPING FRACTURE COST ESTIMATION METHOD

- For desired propped fracture length, the required hydraulic fracture length was calculated.
  - Base case (from current experience)

    $$L_{hyd} = \frac{L_{prop}}{0.6}$$

  - Advanced case (anticipating improvement in the future)

    $$L_{hyd} = \frac{L_{prop}}{0.8}$$

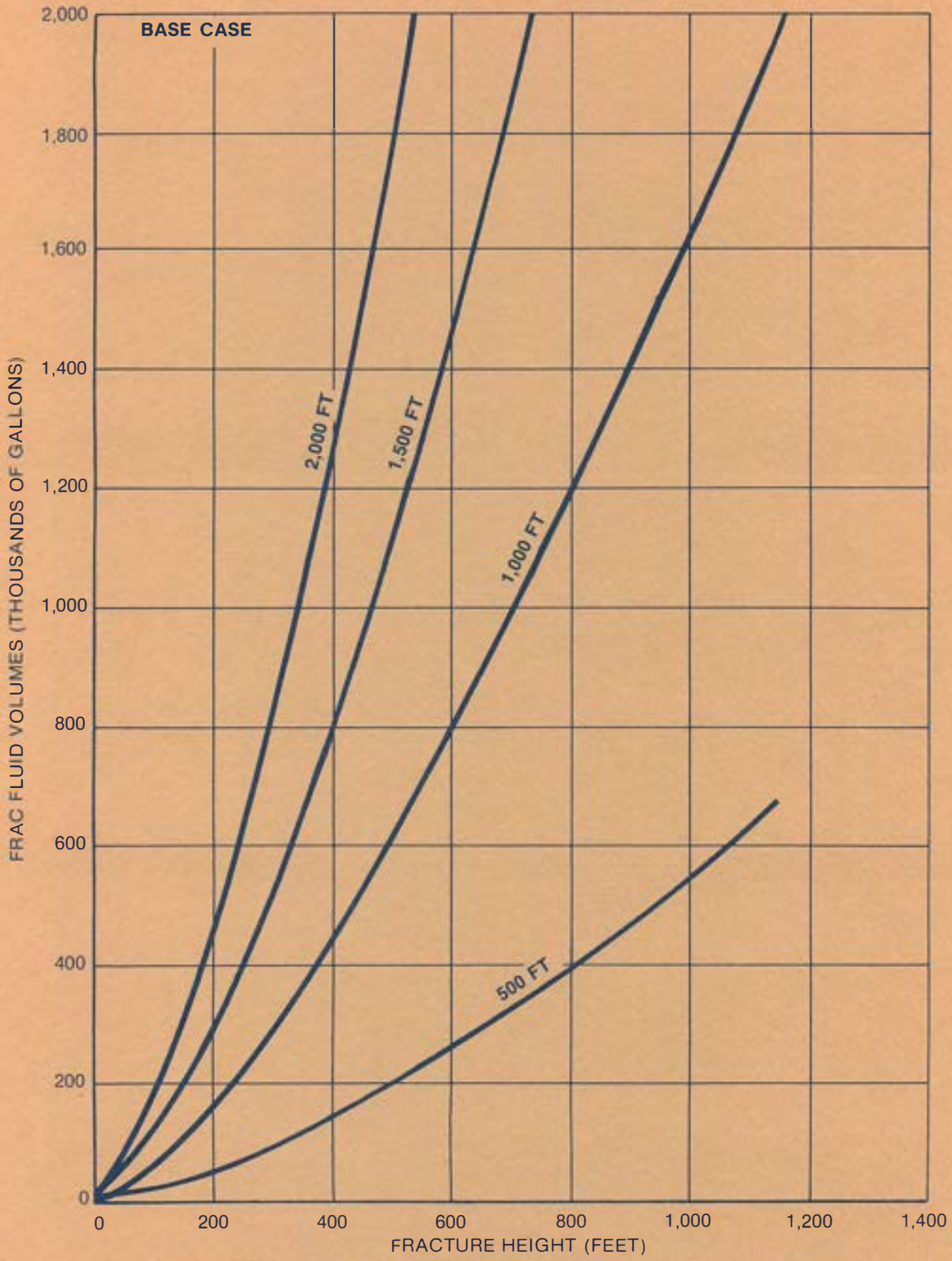


Figure D-3. Frac Fluid Volume Required to Create Fractures of Various Propped Lengths ($L_{prop} = 0.6\ L_{hyd}$).

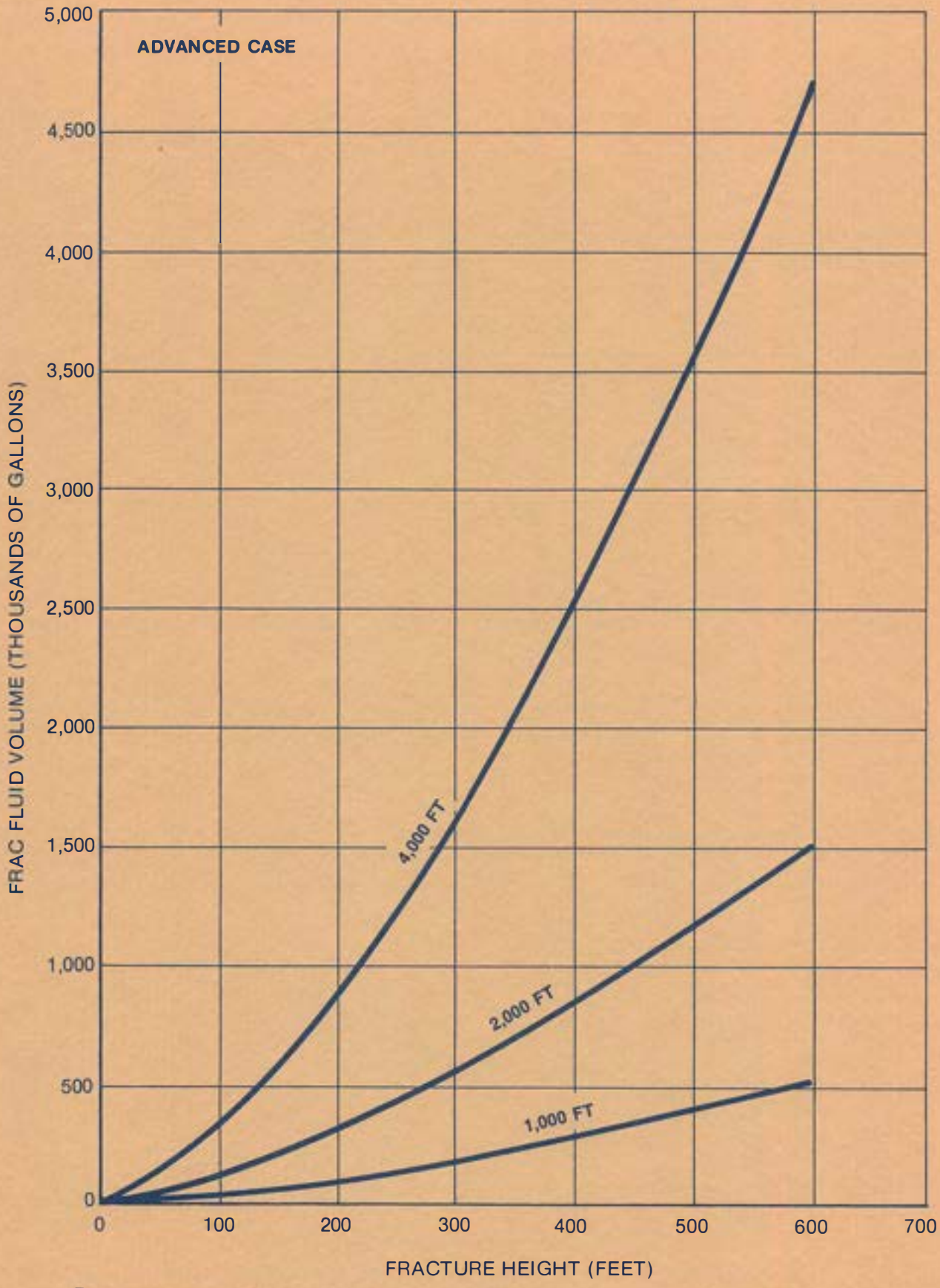


Figure D-4. Frac Fluid Volume Required to Create Fractures of Various Propped Lengths ($L_{prop} = 0.8\ L_{hyd}$).

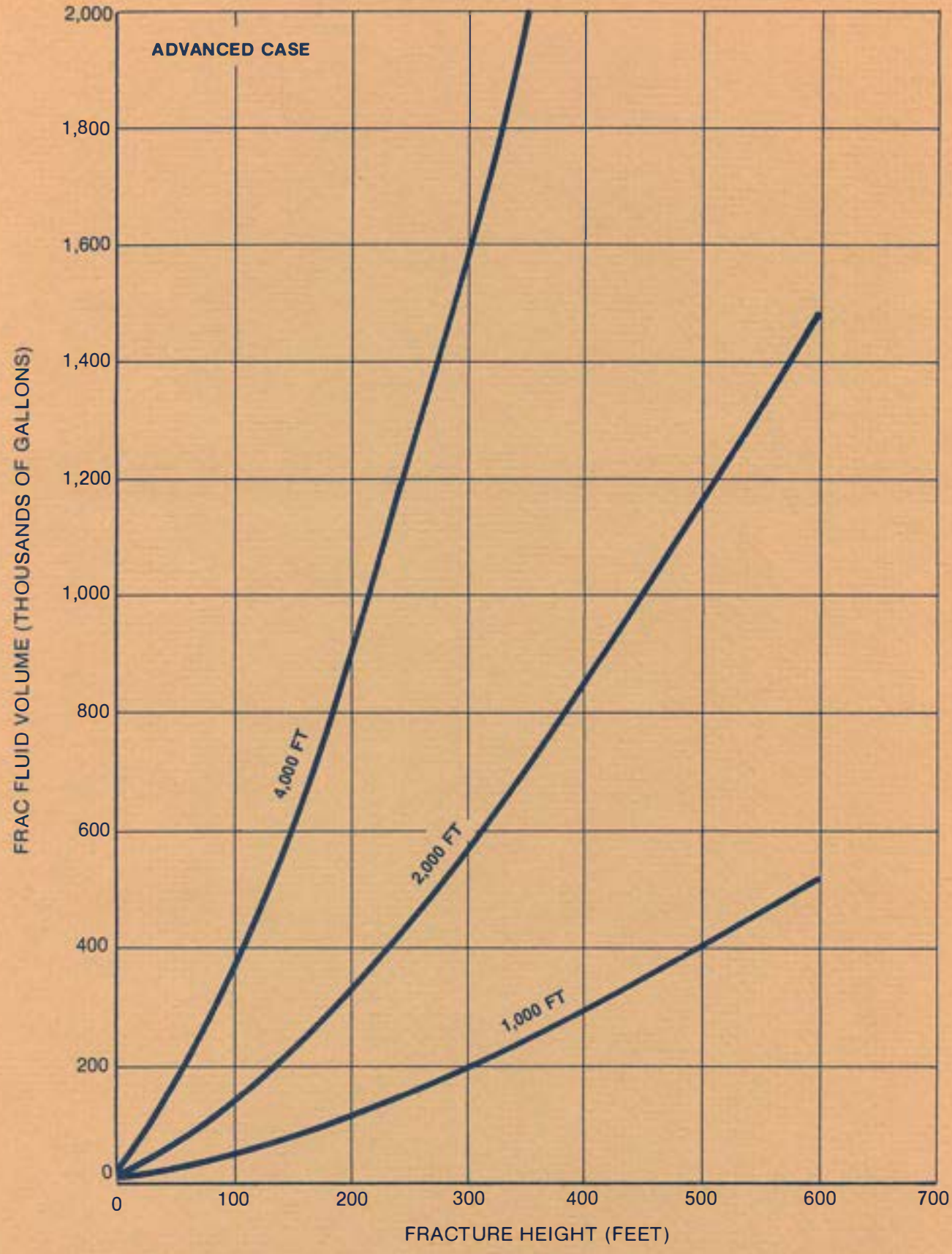


Figure D-5. Frac Fluid Volume Required to Create Fractures of Various Propped Lengths (L_{prop}=0.8 L_{hyd}).

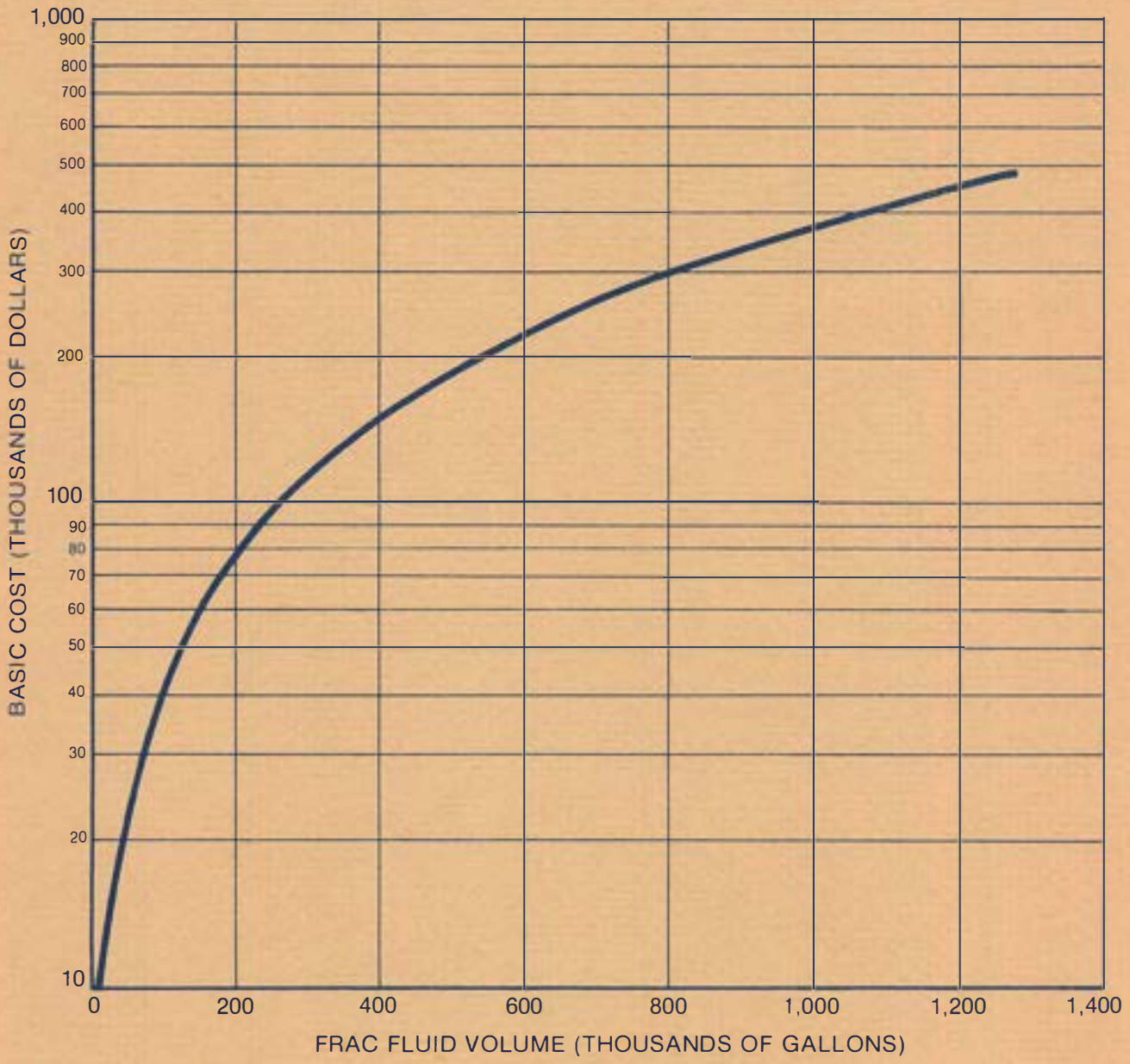


Figure D-6. Basic Cost of Fracturing Treatment as a Function of Fluid Volume.

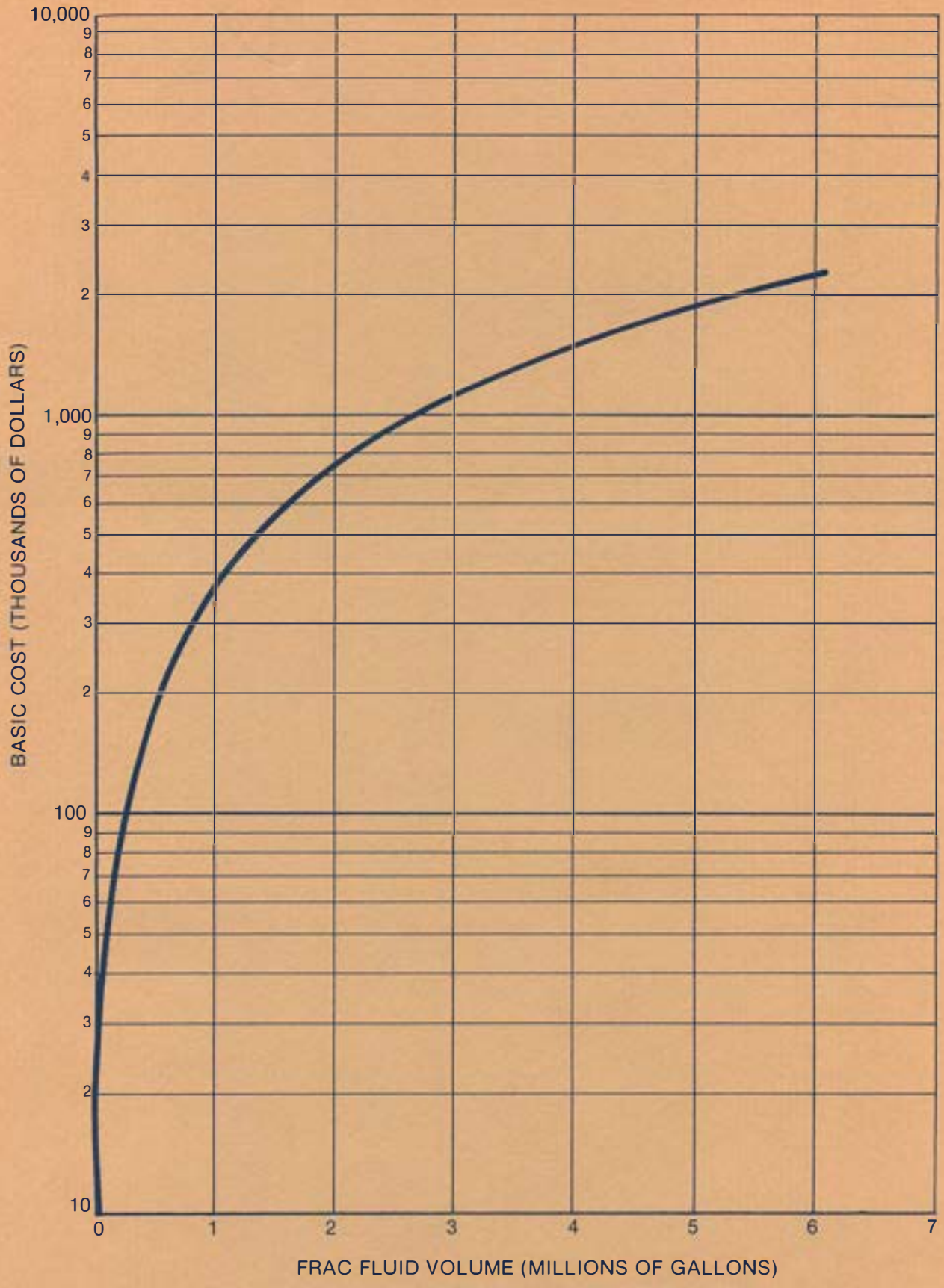


Figure D-7. Basic Cost of Fracturing Treatment as a Function of Fluid Volume.

TABLE D-3

Adjustment Factor for Well Location

Basin	$AF_{Location}$
Sonora, Cotton Valley, and Ouachita	1.15
Denver	1.17
Green River, Wind River, Big Horn, Northern Great Plains, Williston	1.25
San Juan, Uinta, Douglas Creek, Piceance	1.28

TABLE D-4

Adjustment Factor For Depth

Depth	AF_{Depth}
4,000	1.000
6,000	1.063
8,000	1.180
10,000	1.296
12,000	1.310
15,000	1.400

- Volume of fracturing fluid required to create hydraulic fracture length was calculated.
  - Calculation methods

    Fracture area generated -- Carter equation[1]

    Fracture width -- Perkins and Kern equations[2]

[1]Howard, G. C. and Fast, C. R., "Optimum Fluid Characteristics for Fracture Extension," API Drilling and Production Practice (1957), p. 261.

[2]Perkins, T. K. and Kern, L. R., "Widths of Hydraulic Fractures," J. Pet. Tech. (Sept. 1961) 937-949; Trans., AIME, 222.

- Treatment parameters

Reservoir properties:

Perm. = 0.02 md
Por. = 0.10
E = 6,000,000 psi
Depth = 7,684 ft.
Res. Pres. = 2,900 psi
Compr. = 0.000345/psi
Res. Visc. = 0.02 cp
Frac. Ext. Pres. = 5,600 psi

Frac fluid:

Type: 40 to 50 lb/1,000 gal. cross-linked hydroxy guar gelled water with 5 percent oil phase for fluid loss control

Rheological and fluid loss properties:

Slope = 0.70

Intercept = 0.10

c_w = 0.0007 ft/ min

Spurt = 0.10 cc/22.8 cm^2

Propping agent:

Type: Sand

Size: 20/40 mesh

Concentration: 2 lb/gal average

Injection rate: 25 BPM

- Fracture treatment cost data

Representative treatments were submitted to three service companies for cost estimates. Detailed estimates were obtained for frac fluid volumes ranging from 100,000 to 1,200,000 gallons at depths ranging from 4,000 to 12,000 feet. Additional estimates were obtained for specific treatments in various geographic areas. From analysis of these cost data, the estimation scheme presented here was developed.

Essentially, the basic cost of the fracturing treatment (Figures D-6 and D-7) is the cost of a treatment at a depth

of 4,000 feet, done in one of the least expensive areas, such as eastern Texas (Cotton Valley) or western Texas (Sonora). This cost is then adjusted by multiplying by two factors.

ESTIMATED COST OF GATHERING SYSTEMS FOR TIGHT GAS FIELDS

An estimate was made of costs of gathering systems and compressors. Six cases, representing a broad range of field sizes and production rates, were selected; their characteristics are shown in Table D-5. Figure D-8 shows a chart for estimating gathering system costs.

Layouts of a gas gathering system were made for each field; these give an approximate idea of gathering costs.

Pipeline pressures were assumed to decline over the life of the fields, as shown in Table D-6.

TABLE D-5

Cost of Field Gathering Systems
For a Range of Cases

	Case No.					
	1	2	3	4	5	6
Field Size (BCF)	4	80	400	4,000	16	8,000
Field Size (Sections)	2	14	40	500	2	500
Wells Per Field	4	28	80	2,000	16	4,000
Wells Per Section	2	2	2	4	8	8
Design Annual Production Rate Per Well MMCF Per Year Year 1	200	800	1,100	260	200	260
Ultimate Production Per Well (BCF)	1	3	5	2	1	2
Gathering System Cost ($ Per Well)	$23,200	40,400	80,100	47,600	14,300	45,500
Cost ($ Per Well Per BCF of Ultimate Well Production)	23,200	13,500	16,100	23,800	14,300	22,800

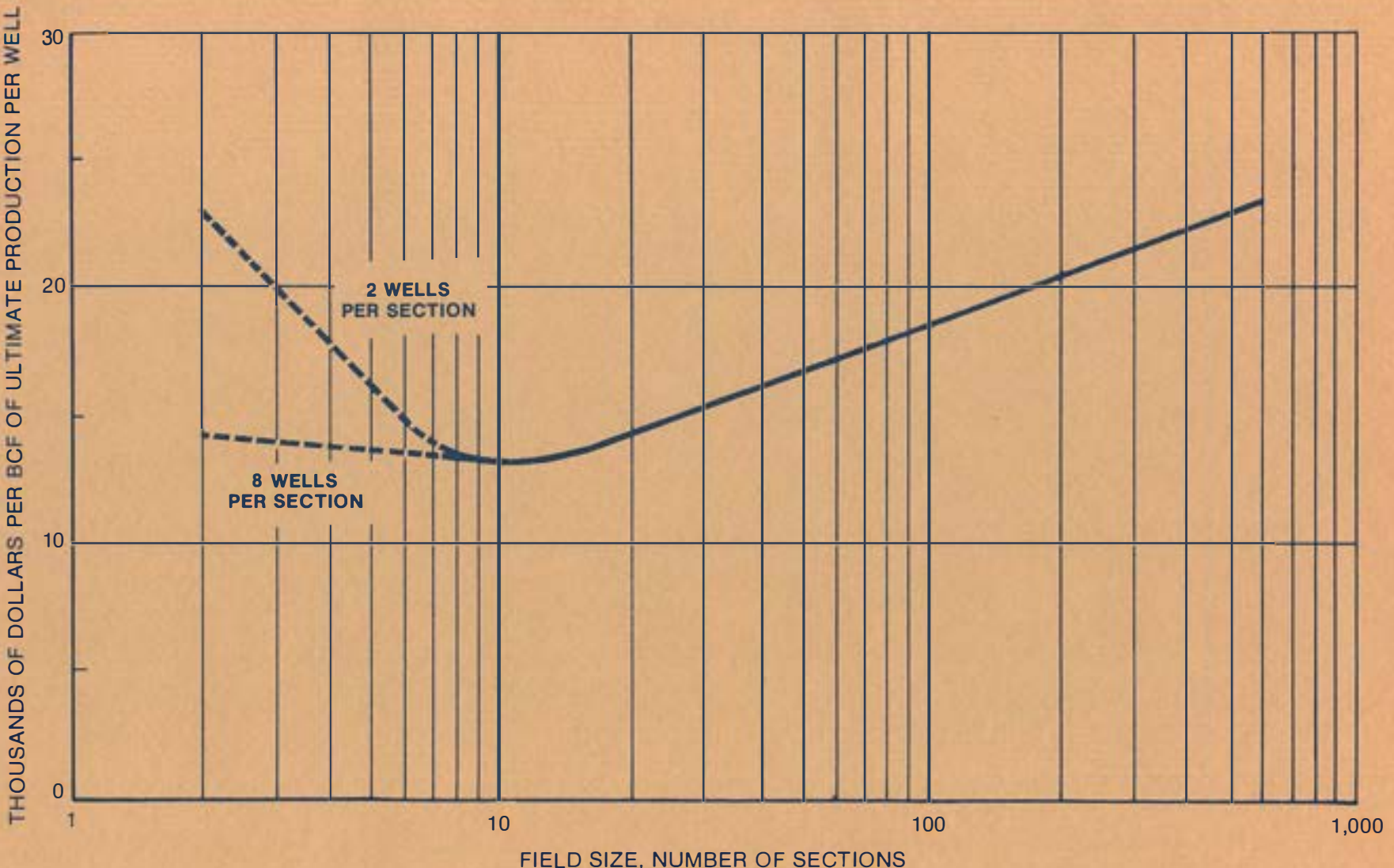


Figure D-8. Gathering System Investment (Thousands of Dollars Per Well for Each BCF of Ultimate Production Per Well).

TABLE D-6

Gathering System Pressures (psia)

	Years			
	1-8	9-19	20-30	30-50
Flowing Bottom Hole Pressure	1360	710	360	85
Well Head Pressure	1130	590	300	70
Field Compressor Suction				80
Field Compressor Discharge				160
Central Compressor Suction		500	250	120
Central Compressor Discharge		1000	1000	1000
Delivery to Gas Transmission Pipeline	1000	1000	1000	1000

Diameters of gathering lines were estimated using the general flow equation converted to the formula for diameter.[3]

The cost of pipelines was obtained from three industry sources and included gas field gathering systems and cross-country transmission lines. Table D-7 illustrates the weighted value for gathering lines as well as the cost of other pipeline and production equipment.

COMPRESSION COSTS

For an economical operation, a cross-county gas transmission pipeline must operate at about 1,000 psia. When the gas field wells can no longer flow into a 1,000 psia pipeline, it is necessary to compress the gas at the terminus of the gathering system. The schedule of compression pressure requirements is shown in Table D-6 for the cases assumed for estimating gathering costs.

Compressor horsepower requirements are estimated in Table D-8 for the compressor operating between sea level and 1,500 feet elevation. At higher elevations, the amount of brake horsepower required must be increased to deliver the same compression horsepower to the gas.

Installed investment costs are estimated in Table D-9 for skid-mounted field compressors at $850 per brake horsepower. The investments are based on engines capable of supplying all the horsepower needed at 250 psia suction pressure. They should be serviceable thoughout the life of the field.

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[3]Baker, Ovid, and Swerdloff, Will, Oil & Gas Journal, May 16, 1955. Use these charts to speed up flow calculations for design of gas-gathering systems.

TABLE D-7

Installed Gas Field Gathering Pipeline Costs, U.S. Average

Pipe Size	Installed Cost* 1979 Dollars/Foot	$/inch/mile
2"	7.00	18,400
4"	10.00	13,200
6"	14.00	12,320
8"	18.00	11,880
10"	23.00	12,150
12"	28.00	12,320
14"	33.00	12,450

*These costs could be 40% higher in heavily populated areas. They could be 20% less in favorable areas. Local area competition is a significant cost factor.

Costs include all materials, right of way, damages, coating and wrapping, contractors' installation charges, and all direct operators' costs.

Production Equipment - Installed Cost	Price Each 1979 Dollars
Skid mounted unit containing separator, heater, gas meter run and meter for dumped liquids	$25,000
210 bbl lease tank	3,000
Dehydrator 3-5 MMCFD capacity	18,500
10 MMCFD capacity	25,000
Meter House	3,500
Pipeline drips	3,200

Compressor operating costs are estimated in Table D-10. These are based on operation and maintenance costs of $50 per brake horsepower per year and fuel costs of 10 cubic feet of gas per horsepower-hour at the field gas selling price. The low operating cost is for automatic, unattended operation of the compressors.

Estimated operating costs for gathering and compression combined is shown in Table D-11 for Case 2 at 1,500 feet elevation, $2.50/MCF fuel price, and compressing from 250 psia to 1,000 psia.

Annual operating costs for the gathering system may be estimated at about 3 percent of the investment cost.

TABLE D-8

Compression Horsepower Requirements

	Per MMCF/D Compressed	
Compressor Suction Pressure, PSIA	250	500
Compressor Discharge Pressure PSIA	1000	1000
Compression Ratio	4	2
N Value for 0.6 SG Gas	1.28	1.28
Brake Horsepower/MMCFD of Gas @ 14.4 psig and Suction Temperature	85.6	44.0
BHP/MMCFD @ 14.65 psia and 60°F	93.8	48.2
Brake Horsepower Hour/Year/MMCF	821,633	422,232
Compressor Fuel Consumed @ 10 cu. Ft. per brake Horsepower hour/MCF/year	8,217	4,222
Fuel as a Percent of Gas Compressed	2.25	1.16

Compressor Engine Efficiency at Various Altitudes

	Efficiency
Sea Level to 1500 ft.	100%
3,000 Ft.	93.5%
6,000 Ft.	81.5%
9,000 Ft.	70.5%

Brake horsepower requirements shown above are increased in the ratio of $\frac{100}{\text{Efficiency}}$ at elevations above 1500 ft.

Brake Horsepower Requirements at Sea Level

Suction PSIA	Discharge PSIA	Case 1	Case 2	Case 3
500	1000	27	730	3240
250	1000	34	912	3677

TABLE D- 9

Compressor Investment Costs

Suction = 250 PSIA, Discharge = 1000 PSIA

Elevation, Ft.	Case 1	Case 2	Case 3
	Horsepower Installed		
1500	34	912	3677
3000	36	975	3933
6000	42	1119	4512
9000	48	1294	5216
	Investment $/Field		
1500	$28,900	$775,200	$3,125,450
3000	30,600	828,750	3,343,000
6000	35,700	951,150	3,835,200
9000	40,800	1,099,900	4,433,600
	Investment $/Well		
1500	$ 7,225	28,710	39,070
3000	7,650	30,690	41,790
6000	8,925	32,230	47,940
9000	10,200	40,740	55,420

TABLE D-10

Compression Operating Costs

Suction = 250 PSIA, Discharge = 1000 PSIA 0-1500 ft. elevation

	Case 1	Case 2	Case 3
Brake Horsepower Installed	34	912	3677
Thousands of BHP hrs/year	298	7,989	32,210
Fuel MMCF/year	2.98	79.9	322.
Fuel Costs $/year @ $2.50/MCF	7,450	199,750	805,000
Operations & Maintenance	1,700	45,600	183,850
	$9,150	$245,350	$988,850

Annual costs for other conditions can be estimated by the equation

$$\text{Operating Cost, \$/year} = \left[\frac{(\text{BHP @ 1500 ft. elev.})\ 100}{\text{Compressor Efficiency}}\right]\left[50 + 87.6\ \text{Fuel Price}\right]$$

Annual $/well	$2,288	$ 9,097	$ 12,360
$/MCF Compressed	0.0696	0.0692	0.0691

TABLE D-11

Operating Cost for Gathering and Compression

	$/Well/Yr.	$/MCF
(94,500)(0.03) = Gathering	$2,835	0.0216
Compressing	9,087	0.0692
	$11,922	0.0908

Conditions

Suction = 250 PSIA, Discharge 1000 PSIA

Elevation 0-1500 ft.

Fuel Price 2.50/MCF

For other conditions, use data from previous tables.

APPENDIX E

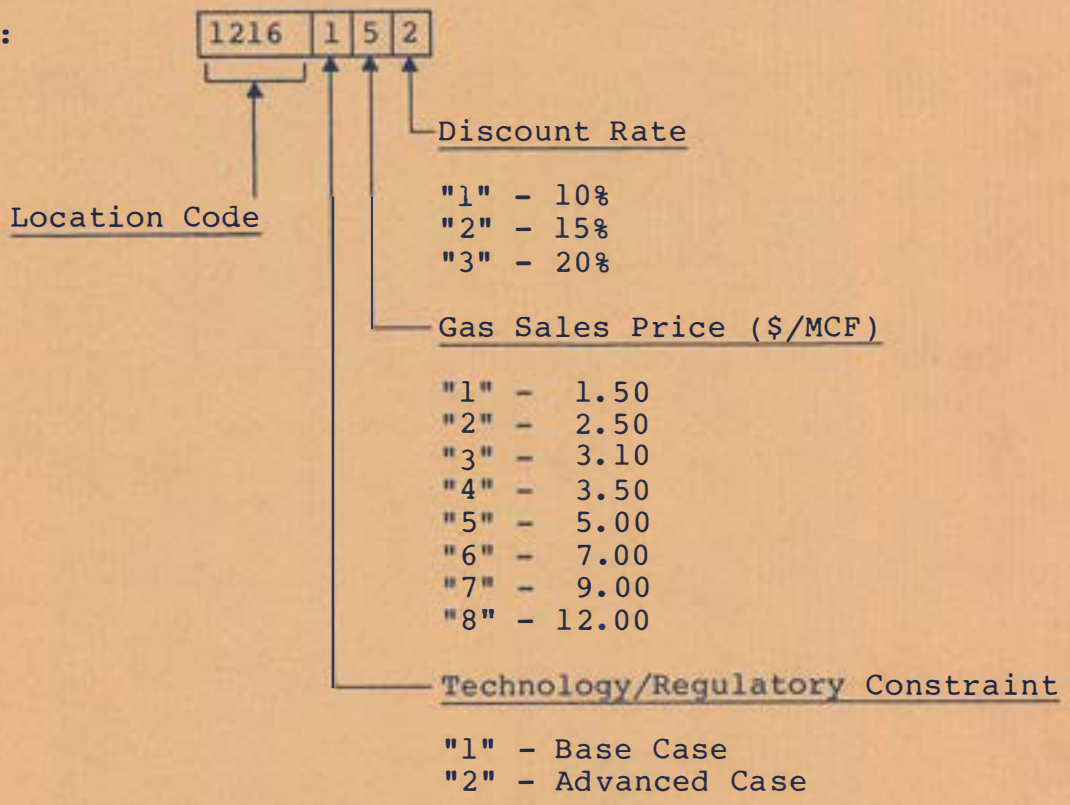
Tight Gas Development Scenarios—Identification of Prospects

TIGHT GAS DEVELOPMENT SCENARIOS -- IDENTIFICATION OF PROSPECTS

Examples of two tight gas development scenarios are included in the following compilations, illustrating the standard scenario for $5.00/MCF price at a 15 percent discount rate as well as the standard scenario for $3.50/MCF at a 15 percent discount rate. Following is a description of the identification of prospects used in these scenarios.

A seven-digit case number is used to identify the prospects used in the scenarios. It appears in the second column of the scenario printout, immediately preceding an abbreviated alphabetic description of the prospect location. The case number consists of a four-digit location code, as well as single digit codes for technology, gas sales prices, and discount rate.

EXAMPLE:



A list of location codes for each of the 82 locations used in the 12-basin tight gas study is included on the pages preceding the compilation. In the example, "1216" refers to the Northern Great Plains/Williston basin, Carlile formation. Following code shows the base case, $5.00/MCF price, at a 15 percent discount rate.

Certain appraised regions are also used to represent other speculative tight gas regions when all of the 113 gas basins in the United States are considered in the scenario. This is discussed in Chapter Five.

TABLE E-1

Location Code

Basin	Subbasin	Formation	Location Code
Northern Great Plains/ Williston		Mowry	1201
		Mowry, Greenhorn	1202
		Mowry, Carlile	1203
		Mowry, Greenhorn, Carlile	1204
		Mowry, Greenhorn, Carlile, Eagle	1205
		Mowry, Greenhorn, Eagle	1206
		Mowry, Judith River	1207
		Mowry, Carlile, Eagle	1209
		Mowry, Carlile, Eagle, Judith River	1211
		Greenhorn	1212
		Greenhorn, Carlile	1213
		Greenhorn, Eagle	1214
		Greenhorn, Carlile, Eagle	1215
		Carlile	1216
		Niobrara	1217
		Carlile, Eagle	1218
		Judith River	1219
		Mowry, Greenhorn, Carlile, Eagle, Judith River	1210
		Carlile, Niobrara	1220
Wind River		Lower Fort Union	1101
		Lance 9,000	2502
		Lance 14,000	2503
		Mesaverde 15,000	1104
		Lower Fort Union, Lance 9,000	2505
		Lance 14,000, Mesaverde 15,000	1106
		Frontier, Muddy	1107
Cotton Valley			2101

TABLE E-1 (Continued)

Basin	Subbasin	Formation	Location Code
Greater Green River	Lewin Area 1	Almond A	0801
		Ericson, Rock Springs, Blair	0802
		Fort Union	0803
		Almond A + Almond B	0804
		Almond A + Ericson, Rock Springs, Blair	0805
		Almond B + Ericson, Rock Springs, Blair	0806
		Lance, Lewis	0807
	Lewin Area 2 & 3	Almond A	0821
		Almond B	2422
		Ericson, Rock Springs, Blair	0823
		Fort Union	0824
		Almond A + Almond B	2425
		Almond B + Ericson, Rock Springs, Blair	0826
		Lance, Lewis	0827
	Washakie		
		Almond	0831
		Lance, Lewis	0832
		Lower Mesaverde	0833
		Lance, Lewis + Almond	0834
		Lower Mesaverde + Almond	0835
	E/2 Lewin Area 4		
		Mesaverde	0841
		Fort Union	0842
		Fort Union + Mesaverde	0843

TABLE E-1 (Continued)

Basin	Subbasin	Formation	Location Code
	W/2 Lewin 4, Bridger Lewin 5	Fort Union	0851
		Mesaverde, Lance	2452
		Frontier	2453
		Mesaverde, Lance + Frontier	2454
		Fort Union + Mesaverde, Lance	2455
Greater Green River	Sand Wash	Lewis 7,000	0811
		Lewis 9,000	0812
		Mesaverde 9,000	0813
		Mesaverde 11,000	0814
		Lewis 7,000 + Mesaverde 9,000	0815
		Mesaverde 9,000 + Mesaverde 11,000	0816
Uinta		Coaly	1003
		Castlegate	1004
		Coaly + Castlegate	1005
		Wasatch + Coaly	1006
		Wasatch + Barren	1007
		Wasatch	1001
		Barren	1002

TABLE E-1 (Continued)

Basin	Subbasin	Formation	Location Code
Denver		Area A	2001
		Area B	0502
Edwards Lime		South West	2201
		Central	2202
Piceance		Corcoran Cozette	1301
		Fort Union	1302
		Mesaverde 8,000	1303
		Corcoran Cozette + Mesaverde	1304
		Fort Union + Mesaverde	1305
		Fort Union + Corcoran Cozette	1306
		Lower Cretaceous, Jurassic	1307
San Juan		Dakota	1601
Val Verde-Sonora			1801
Val Verde-Ozona			2301

TABLE E-2(1)a

Standard Scenario at $5.00 and 15%
Base and Advanced Technology--Northern Great Plains/Williston

CASE 2.40 SCENARIO 1 08/06/80 20 YEAR DEVELOPMENT PROGRAM

	YEAR OF DEVELOPMENT			1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	
	LOCATION OF PROSPECTS--																							
1	1201152	NGP-WIL,M	15., 5.00	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	1202152	NGP-WIL,M G	15., 5.00	0	0	0	2	2	3	2	1	0	0	0	0	0	0	0	0	0	0	0	0	10
3	1203152	NGP-WIL,M C	15., 5.00	0	0	1	1	2	3	4	2	0	0	0	0	0	0	0	0	0	0	0	0	15
4	1204152	NGP-WIL,M G,C	15., 5.00	1	1	2	3	5	10	8	5	0	0	0	0	0	0	0	0	0	0	0	0	35
5	1205152	NGP-WIL,M G,C,E	15., 5.00	5	10	12	15	15	13	10	8	0	0	0	0	0	0	0	0	0	0	0	0	88
6	1206152	NGP-WIL,M G,E	15., 5.00	0	0	0	2	3	5	5	3	0	0	0	0	0	0	0	0	0	0	0	0	18
7	1207152	NGP-WIL,M JR	15., 5.00	0	0	0	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	3
8	1208152	NGP-WIL,M C,E	15., 5.00	2	5	7	7	7	7	7	7	0	0	0	0	0	0	0	0	0	0	0	0	49
9	1209152	NGP-WIL,M C,E,JR	15., 5.00	0	2	5	5	7	7	4	2	0	0	0	0	0	0	0	0	0	0	0	0	32
10	1210152	NGP-WIL,M G,C,E,JR	15., 5.00	1	1	3	3	5	5	4	4	0	0	0	0	0	0	0	0	0	0	0	0	26
11	1211152	NGP-WIL,M C,JR	15., 5.00	0	0	2	2	2	3	3	3	0	0	0	0	0	0	0	0	0	0	0	0	15
12	1212152	NGP-WIL,G	15., 5.00	0	0	0	0	0	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	3
13	1213152	NGP-WIL,G,C	15., 5.00	0	0	0	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	5
14	1214152	NGP-WIL,G,E	15., 5.00	0	1	1	1	2	3	3	3	0	0	0	0	0	0	0	0	0	0	0	0	14
15	1215152	NGP-WIL,G,C,E	15., 5.00	0	0	1	1	3	3	3	3	0	0	0	0	0	0	0	0	0	0	0	0	14
16	1216152	NGP-WIL,C	15., 5.00	0	0	0	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3
17	1217152	NGP-WIL,N	15., 5.00	1	1	2	3	3	3	3	3	1	0	0	0	0	0	0	0	0	0	0	0	20
18	1218152	NGP-WIL,C,E	15., 5.00	0	0	0	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3
19	1219152	NGP-WILLS JUD.RIV	15.0,5.00	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
20	1220152	NGP-WIL C,N	15., 5.00	0	0	1	1	2	2	3	3	0	0	0	0	0	0	0	0	0	0	0	0	12
21	1201252	NGP-WIL M	15., 5.00	0	0	0	0	0	0	0	0	0	0	1	1	2	3	5	7	8	8	6	6	50
22	1202252	NGP-WIL M G	15., 5.00	0	0	0	0	0	2	3	4	4	4	7	7	7	7	7	9	9	9	9	9	97
23	1203252	NGP-WIL M C	15., 5.00	0	0	0	0	1	4	5	5	5	5	5	6	6	9	9	9	9	9	9	9	105
24	1204252	NGP-WIL M G,C	15., 5.00	0	0	0	1	2	8	8	16	16	16	18	18	23	23	26	26	30	30	30	30	321
25	1205252	NGP-WIL M G,C,E	15., 5.00	0	0	3	5	10	13	16	18	26	26	26	26	26	26	26	30	30	30	30	30	397
26	1206252	NGP-WIL M G,E	15., 5.00	0	0	0	0	1	2	4	5	7	10	10	10	10	10	10	8	8	8	8	8	127
27	1207252	NGP-WIL M JR	15., 5.00	0	0	0	1	0	2	4	1	2	5	5	5	7	7	10	10	12	12	12	12	112
28	1208252	NGP-WIL M C,E	15., 5.00	0	0	0	1	2	2	4	7	7	7	9	9	9	11	11	15	15	15	15	15	158
29	1209252	NGP-WIL M C,E,JR	15., 5.00	0	0	0	1	3	7	10	13	15	17	17	21	21	25	25	25	27	27	27	27	308
30	1210252	NGP-WIL M G,C,E,JR	15., 5.00	0	0	0	0	2	5	6	8	10	10	13	13	13	15	15	15	15	17	17	17	191
31	1211252	NGP-WIL M C,JR	15., 5.00	0	0	0	0	1	3	6	7	10	10	10	10	12	12	12	12	14	14	14	14	161
32	1212252	NGP-WIL G	15., 5.00	0	0	0	0	0	0	0	1	1	1	2	2	2	2	2	2	2	2	2	2	23
33	1213252	NGP-WIL G,C	15., 5.00	0	0	0	0	0	1	1	1	2	2	2	2	2	3	3	3	3	3	3	3	34
34	1214252	NGP-WIL C,E	15., 5.00	0	0	0	0	1	3	5	10	13	13	13	13	13	13	13	6	0	0	0	0	116
35	1215252	NGP-WIL G,C,E	15., 5.00	0	0	0	0	1	3	5	7	10	10	10	10	7	7	4	4	4	0	0	0	82
36	1216252	NGP-WIL C	15., 5.00	0	0	0	0	0	0	0	0	1	1	1	1	1	2	2	2	2	2	2	2	19
37	1217252	NGP-WIL N	15., 5.00	0	0	1	1	3	7	12	14	18	20	25	35	37	40	40	42	42	43	43	43	468
38	1218252	NGP-WIL C, E	15., 5.00	0	0	0	0	0	1	2	2	2	3	3	3	3	3	2	2	2	2	2	2	34
39	1219252	NGP-WILLS JUD.RIV	15.0,5.00	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
40	1220252	NGP-WIL C,N	15., 5.00	0	0	0	0	1	2	4	4	7	7	7	7	9	9	4	3	2	0	0	0	66

TABLE E-2(1)b

SUMMARY OF WELL REQUIREMENTS

	CASE	LOCATION OF PROSPECT		NO. PROSP.	WILDCAT WELLS			W/C SUCCESS RATIO	DEVELOPMENT WELLS			TOTAL ALL WELLS
					PROD.	DRY	TOTAL		PROD.	DRY	TOTAL	
1	1201152	NGP-WIL,M	15., 5.00	0	0	0	0	.09	0	0	0	0
2	1202152	NGP-WIL,M G	15., 5.00	10	3	15	18	.17	73	18	91	109
3	1203152	NGP-WIL,M C	15., 5.00	15	5	22	27	.21	119	29	148	175
4	1204152	NGP-WIL,M G,C	15., 5.00	35	12	54	66	.19	182	45	227	293
5	1205152	NGP-WIL,M G,C,E	15., 5.00	88	37	129	166	.23	374	93	467	633
6	1206152	NGP-WIL,M G,E	15., 5.00	18	7	27	34	.21	148	37	185	219
7	1207152	NGP-WIL,M JR	15., 5.00	5	1	7	8	.17	49	12	61	69
8	1208152	NGP-WIL,M C,E	15., 5.00	49	20	71	91	.22	239	59	298	389
9	1209152	NGP-WIL,M C,E,JR	15., 5.00	32	12	48	60	.21	138	34	172	232
10	1210152	NGP-WIL,M G,C,E,JR	15., 5.00	26	10	38	48	.22	55	13	68	116
11	1211152	NGP-WIL,M C,JR	15., 5.00	15	5	22	27	.20	112	28	140	167
12	1212152	NGP-WIL,G	15., 5.00	3	0	4	4	.15	35	8	43	47
13	1213152	NGP-WIL,G,C	15., 5.00	5	2	7	9	.22	53	13	66	75
14	1214152	NGP-WIL,G,E	15., 5.00	14	6	19	25	.25	134	33	167	192
15	1215152	NGP-WIL,G,C,E	15., 5.00	14	5	20	25	.22	61	20	101	126
16	1216152	NGP-WIL,C	15., 5.00	3	1	4	5	.21	56	14	70	75
17	1217152	NGP-WIL,N	15., 5.00	20	3	35	38	.10	40	10	50	88
18	1218152	NGP-WIL,C,E	15., 5.00	3	1	4	5	.21	25	6	31	36
19	1219152	NGP-WILLS JUD.RIV	15.0,5.00	0	0	0	0	I	0	0	0	0
20	1220152	NGP-WIL C,N	15., 5.00	12	4	17	21	.21	55	13	68	89
21	1201252	NGP-WIL M	15., 5.00	50	14	82	96	.15	429	107	536	632
22	1202252	NGP-WIL M G	15., 5.00	97	32	154	186	.17	350	87	437	623
23	1203252	NGP-WIL M C	15., 5.00	105	41	158	199	.21	433	108	541	740
24	1204252	NGP-WIL M G,C	15., 5.00	321	119	498	617	.19	899	224	1123	1740
25	1205252	NGP-WIL M G,C,E	15., 5.00	397	171	581	752	.23	918	229	1147	1899
26	1206252	NGP-WIL M G,E	15., 5.00	127	49	190	239	.21	714	178	892	1131
27	1207252	NGP-WIL M JR	15., 5.00	112	37	174	211	.18	585	146	731	942
28	1208252	NGP-WIL M C,E	15., 5.00	158	67	230	297	.23	448	112	560	857
29	1209252	NGP-WIL M C,E,JR	15., 5.00	308	120	462	582	.21	752	188	940	1522
30	1210252	NGP-WIL M G,C,E,JR	15., 5.00	191	80	279	359	.22	377	94	471	830
31	1211252	NGP-WIL M C,JR	15., 5.00	161	61	243	304	.20	683	170	853	1157
32	1212252	NGP-WIL G	15., 5.00	23	8	35	43	.19	204	51	255	298
33	1213252	NGP-WIL G,C	15., 5.00	34	14	49	63	.23	212	53	265	328
34	1214252	NGP-WIL C,E	15., 5.00	116	54	162	216	.25	694	173	867	1083
35	1215252	NGP-WIL G,C,E	15., 5.00	82	34	120	154	.22	294	73	367	521
36	1216252	NGP-WIL C	15., 5.00	19	7	28	35	.21	188	47	235	270
37	1217252	NGP-WIL N	15., 5.00	468	90	822	912	.10	473	118	591	1503
38	1218252	NGP-WIL C, E	15., 5.00	34	13	50	63	.21	199	49	248	311
39	1219252	NGP-WILLS JUD.RIV	15.0,5.00	0	0	0	0	I	0	0	0	0
40	1220252	NGP-WIL C,N	15., 5.00	66	26	98	124	.21	227	56	283	407

TABLE E-2(1)c

ANNUAL DRILLING SCHEDULE

	PROSPECT		YEAR	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
1	NGP-WIL,M	15.,	5.00	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	NGP-WIL,M,G	15.,	5.00	0	0	0	22	22	33	22	11	0	0	0	0	0	0	0	0	0	0	0	0
3	NGP-WIL,M,C	15.,	5.00	0	0	11	11	23	59	47	23	0	0	0	0	0	0	0	0	0	0	0	0
4	NGP-WIL,M,G,C	15.,	5.00	8	8	16	25	42	84	67	42	0	0	0	0	0	0	0	0	0	0	0	0
5	NGP-WIL,M,G,C,E	15.,	5.00	36	72	86	108	108	93	72	57	0	0	0	0	0	0	0	0	0	0	0	0
6	NGP-WIL,M,G,E	15.,	5.00	0	0	0	24	36	61	61	36	0	0	0	0	0	0	0	0	0	0	0	0
7	NGP-WIL,M,JR	15.,	5.00	0	0	0	14	14	14	14	14	0	0	0	0	0	0	0	0	0	0	0	0
8	NGP-WIL,M,G,E,JR	15.,	5.00	15	39	55	55	55	55	55	55	0	0	0	0	0	0	0	0	0	0	0	0
9	NGP-WIL,M,C,E,JR	15.,	5.00	0	14	36	36	51	51	29	14	0	0	0	0	0	0	0	0	0	0	0	0
10	NGP-WIL,M,G,C,E,JR	15.,	5.00	4	4	13	13	22	22	18	18	0	0	0	0	0	0	0	0	0	0	0	0
11	NGP-WIL,M,C,JR	15.,	5.00	0	0	22	22	22	33	33	33	0	0	0	0	0	0	0	0	0	0	0	0
12	NGP-WIL,G	15.,	5.00	0	0	0	0	0	16	16	16	0	0	0	0	0	0	0	0	0	0	0	0
13	NGP-WIL,G,C	15.,	5.00	0	0	0	15	15	15	15	15	0	0	0	0	0	0	0	0	0	0	0	0
14	NGP-WIL,G,E	15.,	5.00	0	13	13	13	27	41	41	41	0	0	0	0	0	0	0	0	0	0	0	0
15	NGP-WIL,G,C,E	15.,	5.00	0	0	9	9	27	27	27	27	0	0	0	0	0	0	0	0	0	0	0	0
16	NGP-WIL,C	15.,	5.00	0	0	0	25	25	25	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17	NGP-WIL,N	15.,	5.00	4	4	8	13	13	13	13	13	4	0	0	0	0	0	0	0	0	0	0	0
18	NGP-WIL,C,E	15.,	5.00	0	0	0	12	12	12	0	0	0	0	0	0	0	0	0	0	0	0	0	0
19	NGP-WILLS JUD.RIV	15.0	5.00	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
20	NGP-WIL,C,N	15.,	5.00	0	0	7	7	15	15	23	23	0	0	0	0	0	0	0	0	0	0	0	0
21	NGP-WIL,M	15.,	5.00	0	0	0	0	0	0	0	0	0	0	12	12	25	38	88	101	101	101	76	76
22	NGP-WIL,M,G	15.,	5.00	0	0	0	0	0	12	19	25	25	25	45	45	45	45	45	57	57	57	57	57
23	NGP-WIL,M,C	15.,	5.00	0	0	0	0	7	28	35	35	35	35	35	42	42	63	63	63	63	63	63	63
24	NGP-WIL,M,G,C	15.,	5.00	0	0	0	5	10	43	43	86	86	86	97	97	124	124	141	141	162	162	162	162
25	NGP-WIL,M,G,C,E	15.,	5.00	0	0	14	23	47	62	76	86	124	124	124	124	124	124	124	143	143	143	143	143
26	NGP-WIL,M,G,E	15.,	5.00	0	0	0	8	17	34	42	59	85	85	85	85	85	85	68	68	68	68	68	68
27	NGP-WIL,M,JR	15.,	5.00	0	0	0	0	0	0	8	16	41	41	41	58	58	63	83	100	100	100	100	100
28	NGP-WIL,M,C,E	15.,	5.00	0	0	5	10	10	21	21	38	38	38	48	48	48	59	59	81	81	81	81	81
29	NGP-WIL,M,C,JR	15.,	5.00	0	0	0	4	14	34	49	64	74	84	84	103	103	123	123	123	133	133	133	133
30	NGP-WIL,M,G,C,E,JR	15.,	5.00	0	0	0	0	8	21	26	34	43	43	56	56	56	65	65	65	65	74	74	74
31	NGP-WIL,M,C,JR	15.,	5.00	0	0	0	0	7	21	43	50	72	72	72	72	86	86	86	86	100	100	100	100
32	NGP-WIL,G	15.,	5.00	0	0	0	0	0	0	0	12	12	12	25	25	25	25	25	25	25	25	25	25
33	NGP-WIL,G,C	15.,	5.00	0	0	0	0	0	0	9	9	9	19	19	19	19	29	29	29	29	29	29	29
34	NGP-WIL,G,E	15.,	5.00	0	0	0	0	0	9	28	46	93	121	121	121	121	121	121	56	0	0	0	0
35	NGP-WIL,G,C,E	15.,	5.00	0	0	0	0	6	19	31	44	63	63	63	63	44	44	25	25	25	0	0	0
36	NGP-WIL,C	15.,	5.00	0	0	0	0	0	0	0	0	14	14	14	14	14	28	28	28	28	28	28	28
37	NGP-WIL,C,N	15.,	5.00	0	0	0	3	3	22	38	44	57	64	80	112	116	128	128	134	134	138	138	138
38	NGP-WIL,C,E	15.,	5.00	0	0	0	0	0	9	18	18	18	27	27	27	27	27	18	18	18	18	18	18
39	NGP-WILLS JUD.RIV	15.0	5.00	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
40	NGP-WIL,C,N	15.,	5.00	0	0	0	0	6	12	24	24	43	43	43	43	55	55	24	18	12	0	0	0
	TOTAL WELLS IN EACH YEAR			67	154	298	477	686	1044	1081	1175	974	996	1091	1166	1219	1352	1343	1361	1344	1320	1295	1295

TABLE E-2(1)d

INVESTMENT REQUIREMENTS AND RESERVE ADDITIONS

YEAR	INVESTMENT (MM$)	GAS RESERVES ADDED (BCF)	CUMMULATIVE GAS RESERVES
1	20.8	76.7	76.7
2	46.9	166.5	243.2
3	97.1	326.2	569.4
4	154.8	476.8	1046.2
5	242.8	727.8	1774.0
6	390.3	1126.4	2900.4
7	436.4	1241.1	4141.4
8	508.0	1426.0	5567.4
9	505.0	1357.7	6925.1
10	518.2	1387.4	8312.5
11	563.4	1504.6	9817.1
12	601.4	1605.1	11422.2
13	622.2	1667.3	13089.5
14	687.2	1824.3	14913.8
15	674.0	1776.9	16690.8
16	688.4	1814.0	18504.8
17	685.6	1812.3	20317.0
18	672.9	1782.0	22099.0
19	663.4	1770.0	23869.1
20	663.4	1770.0	25639.1
	9442.2	TOTAL INVESTMENT	

TABLE E-2(1)e

CASH FLOW AND PRODUCTION SUMMARY

YEAR	ANNUAL CASH FLOW (MM$)	CUMUL. CASH FLOW (MM$)	ANNUAL NGL PROD'N (MMB)	CUMUL. NGL PROD'N (MMB)	ANNUAL GAS PROD'N (BCF)	CUMUL. GAS PROD'N (BCF)	ANNUAL GAS PROD'N (BCF EQ1)	CUMUL. GAS PROD'N (BCF EQ1)
1	-.4455	-.4455	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2	-3.1427	-3.5882	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
3	-8.4910	-12.0792	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
4	-14.7416	-26.8207	0.0000	0.0000	.6784	.6784	.6784	.6784
5	-24.8334	-51.6541	0.0000	0.0000	3.2341	3.9126	3.2341	3.9126
6	-32.7740	-84.4282	0.0000	0.0000	10.4440	14.3566	10.4440	14.3566
7	-43.1411	-127.5692	0.0000	0.0000	23.7804	38.1370	23.7804	38.1370
8	-39.5155	-167.0848	0.0000	0.0000	45.9367	84.0737	45.9367	84.0737
9	-12.8273	-179.9120	0.0000	0.0000	79.3256	163.3993	79.3256	163.3993
10	28.5595	-151.3525	0.0000	0.0000	125.6877	289.0870	125.6877	289.0870
11	106.7998	-44.5527	0.0000	0.0000	185.1086	474.1956	185.1086	474.1956
12	203.0952	158.5425	0.0000	0.0000	250.8353	725.0309	250.8353	725.0309
13	315.4427	473.9852	0.0000	0.0000	317.0798	1042.1107	317.0798	1042.1107
14	427.4692	901.4544	0.0000	0.0000	380.4740	1422.5846	380.4740	1422.5846
15	534.3431	1435.7975	0.0000	0.0000	442.9782	1865.5628	442.9782	1865.5628
16	639.9120	2075.7095	0.0000	0.0000	507.1547	2372.7175	507.1547	2372.7175
17	761.0255	2836.7350	0.0000	0.0000	574.3093	2947.0268	574.3093	2947.0268
18	873.1613	3709.8964	0.0000	0.0000	642.2873	3589.3142	642.2873	3589.3142
19	999.1382	4709.0346	0.0000	0.0000	711.4064	4300.7206	711.4064	4300.7206
20	1124.5029	5833.5375	0.0000	0.0000	778.2709	5078.9914	778.2709	5078.9914
21	1258.9807	7092.5182	0.0000	0.0000	842.3565	5921.3480	842.3565	5921.3480
22	1430.4947	8523.0128	0.0000	0.0000	903.0651	6824.4130	903.0651	6824.4130
23	1640.1805	10163.1934	0.0000	0.0000	960.4329	7784.8460	960.4329	7784.8460
24	1701.8218	11865.0152	0.0000	0.0000	993.1661	8778.0121	993.1661	8778.0121
25	824.7728	13689.7880	0.0000	0.0000	998.6923	9776.7044	998.6923	9776.7044
26	825.2689	15515.0569	0.0000	0.0000	962.3164	10739.0209	962.3164	10739.0209
27	764.4289	17279.4858	0.0000	0.0000	914.6992	11653.7201	914.6992	11653.7201
28	682.7249	18962.2107	0.0000	0.0000	871.5488	12525.2688	871.5488	12525.2688
29	612.1830	20574.3937	0.0000	0.0000	836.1201	13361.3889	836.1201	13361.3889
30	550.5931	22124.9869	0.0000	0.0000	805.4050	14166.7939	805.4050	14166.7939
31	495.1034	23620.0902	0.0000	0.0000	777.8127	14944.6066	777.8127	14944.6066
32	443.6903	25063.0805	0.0000	0.0000	752.7108	15697.3174	752.7108	15697.3174
33	396.6523	26460.6328	0.0000	0.0000	729.8327	16427.1501	729.8327	16427.1501
34	352.9091	27813.5419	0.0000	0.0000	708.7712	17135.9213	708.7712	17135.9213
35	312.0689	29125.6108	0.0000	0.0000	688.9630	17824.8844	688.9630	17824.8844
36	272.7145	30398.3253	0.0000	0.0000	669.5408	18494.4252	669.5408	18494.4252
37	233.2674	31631.5926	0.0000	0.0000	649.7576	19144.1828	649.7576	19144.1828
38	192.0350	32823.6277	0.0000	0.0000	628.8569	19773.0397	628.8569	19773.0397
39	147.4864	33971.1141	0.0000	0.0000	606.0990	20379.1387	606.0990	20379.1387
40	098.2344	35069.3485	0.0000	0.0000	580.7599	20959.8986	580.7599	20959.8986
41	043.8065	36113.1551	0.0000	0.0000	552.5919	21512.4905	552.5919	21512.4905
42	984.3370	37097.4921	0.0000	0.0000	521.6701	22034.1606	521.6701	22034.1606
43	920.8897	38018.3817	0.0000	0.0000	488.5712	22522.7318	488.5712	22522.7318
44	854.3042	38872.6859	0.0000	0.0000	453.7764	22976.5082	453.7764	22976.5082
45	785.3994	39658.0853	0.0000	0.0000	417.7206	23394.2289	417.7206	23394.2289
46	713.9393	40372.0246	0.0000	0.0000	380.2870	23774.5159	380.2870	23774.5159
47	640.2528	41012.2774	0.0000	0.0000	341.6138	24116.1297	341.6138	24116.1297
48	566.0534	41578.3307	0.0000	0.0000	302.5923	24418.7220	302.5923	24418.7220
49	490.4166	42068.7473	0.0000	0.0000	262.7599	24681.4819	262.7599	24681.4819
50	414.7332	42483.4806	0.0000	0.0000	222.7926	24904.2745	222.7926	24904.2745
51	340.6687	42824.1493	0.0000	0.0000	183.5459	25087.8204	183.5459	25087.8204
52	270.4898	43094.6391	0.0000	0.0000	146.2049	25234.0252	146.2049	25234.0252
53	205.0688	43299.7080	0.0000	0.0000	111.2706	25345.2958	111.2706	25345.2958
54	146.7074	43446.4154	0.0000	0.0000	79.9165	25425.2123	79.9165	25425.2123
55	97.7025	43544.1178	0.0000	0.0000	53.4686	25478.6808	53.4686	25478.6808
56	60.7111	43604.8289	0.0000	0.0000	33.3029	25511.9838	33.3029	25511.9838
57	37.0680	43641.8969	0.0000	0.0000	20.4404	25532.4242	20.4404	25532.4242
58	22.8081	43664.7050	0.0000	0.0000	12.6037	25545.0278	12.6037	25545.0278
59	17.7404	43682.4455	0.0000	0.0000	9.8451	25554.8730	9.8451	25554.8730
60	15.5759	43698.0214	0.0000	0.0000	8.6704	25563.5434	8.6704	25563.5434
61	13.9007	43711.9221	0.0000	0.0000	7.7608	25571.3042	7.7608	25571.3042
62	12.4195	43724.3416	0.0000	0.0000	6.9515	25578.2557	6.9515	25578.2557
63	10.8439	43735.1855	0.0000	0.0000	6.0868	25584.3425	6.0868	25584.3425
64	9.5063	43744.6918	0.0000	0.0000	5.3374	25589.6798	5.3374	25589.6798
65	8.1300	43752.8218	0.0000	0.0000	4.5662	25594.2460	4.5662	25594.2460
66	6.6210	43759.4428	0.0000	0.0000	3.7179	25597.9640	3.7179	25597.9640
67	4.9658	43764.4086	0.0000	0.0000	2.7885	25600.7524	2.7885	25600.7524
68	3.3105	43767.7191	0.0000	0.0000	1.8590	25602.6114	1.8590	25602.6114
69	1.6553	43769.3743	0.0000	0.0000	.9295	25603.5409	.9295	25603.5409

25604. BCF--MAX GAS PRODUCED IN SCENARIO

TABLE E-2(1)f

ECONOMIC SUMMARY

PROFIT INDICATORS

DISCOUNTED PRESENT WORTH AT 15.0 PCT. (MM$)	1204.53280
DCF RATE OF RETURN (PERCENT)	43.80
PAYOUT TIME (YEARS)	10.22
PROFIT PER INVESTMENT ($/$)	4.636
MAX. UNRECOVERED INVESTMENT (MM$)	179.9120
NET CASH RECOVERY AFTER TAX (MM$)	43769.3743
EXPLORATION EXPENDITURE (MM$)	3433.8261
PRODUCTION INVESTMENT (MM$)	6248.4822
TOTAL INVESTMENT (MM$)	9442.1958
OPERATING EXPENSE (MM$)	10354.5341

TABLE E-2(2)a

Standard Scenario at $5.00 and 15%
Base and Advanced Technologies--Rocky Mountains

$5.00 @ 15% 08/01/80 20 YEAR DEVELOPMENT PROGRAM

	YEAR OF DEVELOPMENT		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	
	LOCATION OF PROSPECTS--																						
1	0502152	DENVER 8 15.0,5.00	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	0801152	GGR LEWIN 1 ALMD A 15., 5.00	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	7
3	0802152	GGR,LEW 1, E,R,S,B 15.0,5.00	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4	0803152	GGR LEWIN 1 FT UNION15., 5.00	0	0	0	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	8
5	0804152	GGR LEWIN 1 ALMD A~B15., 5.00	5	5	5	5	5	5	5	3	2	1	0	0	0	0	0	0	0	0	0	0	43
6	0805152	GGR LN 1 AL A~E,R$,B15., 5.00	3	2	3	2	3	10	9	7	5	3	1	0	0	0	0	0	0	0	0	0	48
7	0806152	GGR LN 1 AL B+E,R$,B15., 5.00	5	5	5	5	5	10	9	7	5	3	2	0	0	0	0	0	0	0	0	0	61
8	0807152	GGR LN 1 AL LAN,LES 15., 5.00	5	5	5	5	5	10	9	7	5	3	1	0	0	0	0	0	0	0	0	0	60
9	0811152	GGR S/WASH LENS 7000 15., 5.00	0	0	0	0	1	1	1	3	3	2	2	0	0	0	0	0	0	0	0	0	13
10	0812152	GGR S/WASH LENS 9000 15., 5.00	0	0	0	0	0	0	0	1	1	1	1	0	0	0	0	0	0	0	0	0	4
11	0813152	GGR,S/WSH, MV 9000 15.0,5.00	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	0814152	GGR,S/WSH, MV 11000 15.0,5.00	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13	0815152	GGR S/W L7000+MV900015., 5.00	0	0	0	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0	2
14	0816152	GGR,S/WSH,M9000,1100 15.0,5.00	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15	0821152	GGR LN 2/3 ALMOND A 15., 5.00	0	0	1	1	1	2	2	2	1	1	1	0	0	0	0	0	0	0	0	0	12
16	0823152	GGR LN 2/3 E,R$,B 15., 5.00	0	0	0	0	0	0	1	1	1	1	1	0	0	0	0	0	0	0	0	0	5
17	0824152	GGR LN 2/3 FT UNION 15., 5.00	0	0	0	0	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	7
18	0826152	GGR LN2/3 AL B+E,R,B15., 5.00	0	0	1	3	5	5	5	5	4	2	1	0	0	0	0	0	0	0	0	0	31
19	0827152	GGR LN2/3 LNCE+LEWS 15., 5.00	0	1	2	3	3	3	3	3	4	3	1	0	0	0	0	0	0	0	0	0	26
20	0831152	GGR WKIE ALMOND 15., 5.00	0	0	0	0	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	4
21	0832152	GGR WKIE LNCE + LEWS15., 5.00	0	0	0	0	0	0	1	1	1	1	0	0	0	0	0	0	0	0	0	0	4
22	0833152	GGR,WASKIE L.M.V 15.0,5.00	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
23	0834152	GGR WKIE LNCE,LWS+AL15., 5.00	3	5	5	7	10	10	9	7	5	3	0	0	0	0	0	0	0	0	0	0	64
24	0835152	GGR WKIE AL +L.M.VDE15., 5.00	0	0	0	1	1	2	2	2	1	1	0	0	0	0	0	0	0	0	0	0	10
25	0841152	GGR,E/2,L4 M.VERDE 15.0,5.00	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
26	0842152	GGR E/2 L4 FT UNION15., 5.00	0	0	0	1	1	2	3	3	2	1	0	0	0	0	0	0	0	0	0	0	13
27	0843152	GGR E/2 L4 F UN+MV 15., 5.00	0	0	0	0	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	6
28	0851152	GGR,B,L5,W/2L4,FT/UN 15.0,5.00	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
29	0852152	GGR,B,L5,W/2L4,L+MV 15.0,5.00	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
30	1001152	UINTA WASATCH 15., 5.00	3	4	6	8	8	8	7	6	4	2	0	0	0	0	0	0	0	0	0	0	56
31	1002152	UINTA BARREN 15., 5.00	3	4	7	10	10	10	9	7	5	3	0	0	0	0	0	0	0	0	0	0	68
32	1003152	UINTA COALY 15., 5.00	0	1	2	2	2	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	9
33	1004152	UINTA , CASTLEGATE 15.0,5.00	0	1	1	2	2	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	8
34	1005152	UINTA , COALY +CASGT 15.0,5.00	0	1	1	3	3	3	3	2	1	0	0	0	0	0	0	0	0	0	0	0	17
35	1006152	UINTA WASATCH COALY 15., 5.00	3	5	7	9	7	5	3	1	0	0	0	0	0	0	0	0	0	0	0	0	40
36	1007152	UINTA WASATCH BARREN15., 5.00	5	8	11	15	15	13	10	7	4	1	0	0	0	0	0	0	0	0	0	0	88
37	1101152	WIND R. LWR FT UNION15., 5.00	10	15	20	25	25	19	18	14	10	6	2	0	0	0	0	0	0	0	0	0	161
38	1104152	W.RIVER , M.V.15000 15.0,5.00	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
39	1106152	W/R ,LA14000+MV15000 15.0,5.00	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
40	1107152	WIND R.FRONTIER MUDDY15., 5.00	3	4	5	6	5	4	3	2	1	0	0	0	0	0	0	0	0	0	0	0	31
41	1301152	ORCORAN COZET 15., 5.00	2	2	3	4	7	7	6	6	4	1	0	0	0	0	0	0	0	0	0	0	42
42	1302152	PICEANCE,FT UNION 15., 5.00	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	9
43	1303152	PICEANCE,M V 8000 15., 5.00	2	5	4	5	7	7	6	6	5	3	0	0	0	0	0	0	0	0	0	0	63
44	1304152	PICEANCE,COR-COZ MV 15., 5.00	2	5	6	5	7	7	6	4	2	1	0	0	0	0	0	0	0	0	0	0	44
45	1305152	PICEANCE,FTU MV 15., 5.00	1	2	3	5	7	7	5	4	3	2	0	0	0	0	0	0	0	0	0	0	39
46	1306152	PICEANCE,FTU COR-COZ15., 5.00	1	2	3	5	5	4	3	2	1	0	0	0	0	0	0	0	0	0	0	0	26
47	1307152	PICEANCE,LWRCRET JNR15., 5.00	0	0	1	2	3	3	4	3	2	1	0	0	0	0	0	0	0	0	0	0	19
48	2001152	DENVER MUDDY J 15.0,5.00	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

TABLE E-2(2)b

49	0502252	DENVER B	15.0,5.00	0	0	0	0	0	0	1	1	1	1	1	2	2	2	2	2	2	3	3	3	26
50	0801252	GGR LEW 1 ALMD A	15., 5.00	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	13
51	0802252	GGR LEW 1 E,RS,BL	15., 5.00	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	2	2	3	3	3	24
52	0803252	GGR LEW 1 FT UNION	15., 5.00	0	0	0	0	0	0	0	1	1	2	2	5	5	7	7	7	7	7	7	7	61
53	0804252	GGR LEW 1 ALMD A+B	15., 5.00	0	0	0	0	0	0	1	2	3	3	4	5	5	5	5	5	5	5	5	4	56
54	0805252	GGR LEW 1 AL A+E,R,B	15., 5.00	0	0	0	0	0	1	3	5	7	9	12	12	12	12	12	12	12	12	12	12	137
55	0806252	GGR LEW 1 AL B+E,R,B	15., 5.00	0	0	0	0	0	1	3	5	7	13	15	15	15	15	15	15	15	15	15	15	164
56	0807252	GGR LEW 1 LNCE,LEWIS	15., 5.00	0	0	0	0	0	1	3	5	7	9	10	10	10	10	10	10	10	10	10	10	115
57	0811252	GGR S/NASH LWS 7000	15., 5.00	0	0	0	0	0	1	5	10	10	10	10	10	10	10	10	10	10	10	10	10	121
58	0812252	GGR S/NASH LWS 9000	15., 5.00	0	0	0	0	0	1	5	5	5	5	5	5	5	5	5	5	5	5	5	5	53
59	0813252	GGR,S/WSH, MV 9000	15.0,5.00	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
60	0814252	GGR,S/WSH, MV 11000	15.0,5.00	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
61	0815252	GGR S/W L7000+MV9000	15., 5.00	0	0	0	0	0	0	0	0	1	1	4	5	5	5	5	5	5	5	5	5	51
62	0816252	GGR S/W MV9000+1100	15., 5.00	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	6
63	0821252	GGR L2/3 ALMD A	15., 5.00	0	0	0	0	0	0	0	0	2	2	5	10	10	10	10	10	10	10	10	10	99
64	0823252	GGR L2/3 E,RS,BL	15., 5.00	0	0	0	0	0	0	0	1	1	2	2	10	10	12	13	15	15	15	15	15	113
65	0824252	GGR L2/3 FT UNION	15., 5.00	0	0	0	0	0	0	0	0	1	2	5	5	10	10	10	10	10	10	10	10	95
66	0826252	GGR L2/3 AL B+E,RS,B	15., 5.00	0	0	0	0	0	0	1	1	3	5	9	10	10	10	10	10	10	10	10	10	109
67	0827252	GGR L2/3 LANCE/LEWIS	15., 5.00	0	0	0	0	0	0	1	1	3	5	7	10	10	10	10	10	10	10	10	10	116
68	0831252	GGR WSKLE ALMOND	15., 5.00	0	0	0	0	0	0	0	0	1	2	2	2	2	2	2	2	1	1	0	0	16
69	0832252	GGR WSKLE LNCE/LEWS	15., 5.00	0	0	0	0	0	0	0	0	1	1	2	2	2	2	5	5	5	5	5	5	43
70	0833252	GGR,WASKIE L.M.V	15.0,5.00	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
71	0834252	GGR WSKLE LN/LE +AL	15., 5.00	0	0	0	0	0	0	0	1	3	5	7	4	0	0	0	0	0	0	0	0	20
72	0835252	GGR WSKLE ALD +L.M.V	15., 5.00	0	0	0	0	0	0	0	1	2	3	5	7	10	10	10	8	6	4	2	0	68
73	0841252	GGR,E/2,L4 M.VERDE	15.0,5.00	0	0	0	0	0	0	0	0	1	0	2	0	0	0	0	0	0	0	0	0	0
74	0842252	GGR E/2 L4 FT UNION	15., 5.00	0	0	0	0	0	0	0	1	2	2	3	5	7	10	10	10	10	9	8	5	85
75	0843252	GGR,E/2 L4 F/UN+M.V	15.0,5.00	0	0	0	0	0	0	0	1	1	2	2	5	5	7	7	7	7	7	7	7	72
76	0851252	GGR B.L2,W/2L4 F UNN	15., 5.00	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	2	2	2	5	5	21
77	0852252	GGR,B,L5,W/2L4,L+MV	15.0,5.00	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
78	1001252	UINTA WASATCH	15., 5.00	0	0	0	0	0	0	0	1	2	4	6	6	7	7	5	5	5	5	8	10	10	81
79	1002252	UINTA BARREN	15., 5.00	0	0	0	0	0	0	1	3	5	7	5	5	5	5	5	5	5	5	5	5	66
80	1003252	UINTA COALY	15., 5.00	0	0	0	1	1	2	2	2	3	3	3	3	3	2	2	1	0	4	0	4	29
81	1004252	UINTA CASTLEGATE	15., 5.00	0	0	0	0	0	0	2	2	2	2	2	3	3	3	3	4	4	4	4	4	43
82	1005252	UINTA COALY CSTLGT	15., 5.00	0	0	1	2	3	3	5	5	5	3	3	2	2	2	2	2	2	2	2	2	51
83	1006252	UINTA WASATCH COALY	15., 5.00	0	0	0	1	3	5	7	9	10	10	10	10	10	10	10	10	10	7	7	7	130
84	1007252	UINTA WASATCH BARREN	15., 5.00	0	0	0	0	1	1	4	7	10	9	7	7	7	7	7	7	7	7	7	7	95
85	1101252	WIND R. LWR FT UNION	15., 5.00	0	0	0	0	0	2	6	10	14	18	20	20	20	20	20	20	20	20	20	20	230
86	1104252	W.RIVER , M.V.15000	15.0,5.00	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
87	1106252	W/RIV,L14000,MV15000	15.0,5.00	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
88	1107252	WIND R.FRONTIER MDDY	15., 5.00	0	0	0	1	2	3	4	5	7	7	7	7	7	7	7	7	7	7	4	3	92
89	1301252	PICEANCE,COR-COZ	15., 5.00	0	0	0	0	0	0	1	3	4	4	10	10	10	10	10	10	10	10	10	10	112
90	1302252	PICEANCE,FT UNION	15., 5.00	0	0	0	0	0	0	1	1	2	2	2	2	3	3	3	4	4	4	4	4	39
91	1303252	PICEANCE,M V 8000	15., 5.00	0	0	0	0	0	0	1	3	4	4	11	11	13	13	16	16	16	16	16	16	156
92	1304252	PICEANCE,COR-COZ MV	15., 5.00	0	0	0	0	0	0	1	3	5	7	10	10	10	10	9	9	7	7	5	5	98
93	1305252	PICEANCE,FTU MV	15., 5.00	0	0	0	0	0	0	1	3	4	7	7	7	7	5	4	3	2	1	0	0	51
94	1306252	PICEANCE,FTU COR-COZ	15., 5.00	0	0	0	0	0	0	1	3	4	4	4	3	2	2	1	1	0	0	0	0	25
95	1307252	PICEANCE,LWRCRET JUR	15., 5.00	0	0	0	0	0	0	1	3	4	5	6	6	6	6	6	7	7	7	7	7	78
96	2001252	DENVER MUDDY J	15.0,5.00	0	0	0	0	0	0	1	1	5	5	5	10	10	10	10	20	20	25	25	25	172
97	2422152	GGR,LEN2+3, AL B	15.0,5.00	0	0	0	0	0	0	1	1	1	1	1	0	0	0	0	0	0	0	0	0	5
98	2425152	GGR,LEN2+3, AL A+B	15.0,5.00	0	0	0	1	1	2	2	3	3	2	1	0	0	0	0	0	0	0	0	0	15
99	2453152	GGR,W/2L4,B,L5,FRNTR	15.0,5.00	0	0	0	0	0	0	0	1	1	1	0	0	0	0	0	0	0	0	0	0	3
100	2454152	GGR,W/2L4,B,L5,MVL+F	15.0,5.00	0	0	0	0	0	0	0	1	1	1	1	0	0	0	0	0	0	0	0	0	5
101	2455152	GGR,B,L5,W/2L4,FU+MVL	15.0,5.00	0	0	0	0	0	0	0	1	2	1	0	0	0	0	0	0	0	0	0	0	3
102	2502152	WIND R. LANCE 9000	15.0,5.00	0	0	0	0	0	0	1	3	3	2	1	0	0	0	0	0	0	0	0	0	11
103	2503152	WIND R. LANCE 14000	15.0,5.00	0	0	0	0	0	0	0	1	1	1	0	0	0	0	0	0	0	0	0	0	3
104	2505152	WIND R. LFU +LN9000	15.0,5.00	1	4	5	7	7	7	6	5	4	3	2	0	0	0	0	0	0	0	0	0	51
105	2422252	GGR,LEN2+3, AL B	15.0,5.00	0	0	0	0	0	0	0	1	1	1	1	2	2	2	2	2	2	2	2	2	22
106	2425252	GGR,LEN2+3,AL A+B	15.0,5.00	0	0	0	0	0	0	0	1	1	0	3	4	5	10	10	10	10	10	10	10	96
107	2453252	GGR,W/2L4,B,L5,FRNTR	15.0,5.00	0	0	0	0	0	0	0	0	1	0	1	1	3	5	5	7	7	7	7	9	61
108	2455252	GGR,W/2L4,B,L5,MVL+F	15.0,5.00	0	0	0	0	0	0	0	1	2	2	2	2	2	2	2	2	2	2	2	2	27
109	2455252	GGR,W/2L4,B,L5,FU+MVL	15.0,5.00	0	0	0	0	0	0	0	0	1	1	0	1	0	1	1	1	1	1	1	1	10
110	2502252	WIND R. LANCE 9000	15.0,5.00	0	0	0	0	0	0	0	0	1	2	4	5	5	5	5	5	5	5	5	5	55
111	2503252	WIND R. LANCE 14000	15.0,5.00	0	0	0	0	0	0	0	0	1	1	1	2	2	2	3	3	3	3	3	3	25
112	2505252	WIND R. LFU +LN9000	15.0,5.00	0	0	0	0	0	0	1	2	3	4	5	7	7	7	7	7	7	7	4	3	71

TABLE E-2(2)c

SUMMARY OF WELL REQUIREMENTS

	CASE	LOCATION OF PROSPECT	NO. PROSP.	WILDCAT WELLS PROD.	WILDCAT WELLS DRY	WILDCAT WELLS TOTAL	W/C SUCCESS RATIO	DEVELOPMENT WELLS PROD.	DEVELOPMENT WELLS DRY	DEVELOPMENT WELLS TOTAL	TOTAL ALL WELLS
1	0502152	DENVER B 15.0,5.00	0	0	0	0	I	0	0	0	0
2	0301152	GGR LEWIN 1 ALMD A 15., 5.00	7	4	2	6	.58	29	7	36	42
3	0802152	GGR,LEW 1, E,R,S,D 15.0,5.00	0	0	0	0	I	0	0	0	0
4	0803152	GGR LEWIN 1 FT UNION15., 5.00	8	2	5	7	.31	4	1	5	12
5	0804152	GGR LEWIN 1 ALMD A~B15., 5.00	43	32	10	42	.76	101	25	126	168
6	0805152	GGR LN 1 AL A~E,RS,B15., 5.00	48	28	18	46	.60	34	8	42	88
7	0806152	GGR LN 1 AL B+E,RS,B15., 5.00	61	26	34	60	.43	73	18	91	151
8	0807152	GGR LN 1 AL LAN,LES 15., 5.00	60	21	38	59	.36	207	51	258	317
9	0811152	GGR S/WASH LENS 700015., 5.00	13	4	8	12	.36	19	4	23	35
10	0812152	GGR S/WASH LENS 900015., 5.00	4	1	2	3	.28	5	1	6	9
11	0813152	GGR,S/WSH, MV 9000 15.0,5.00	0	0	0	0	I	0	0	0	0
12	0814152	GGR,S/WSH, MV 11000 15.0,5.00	0	0	0	0	I	0	0	0	0
13	0815152	GGR S/W [illegible] 5.00	2	0	1	1	.31	1	0	1	2
14	0816152	GGR,S/WSH,M9000,1100 15.0,5.00	0	0	0	0	I	0	0	0	0
15	0821152	GGR LN 2/3 ALMOND A 15., 5.00	12	4	7	11	.39	13	3	16	27
16	0823152	GGR LN 2/3 E,RS,BL 15., 5.00	5	1	3	4	.27	14	3	17	21
17	0824152	GGR LN 2/3 FT UNION 15., 5.00	7	3	3	6	.52	8	2	10	16
18	0826152	GGR LN2/3 AL B+E,R,B15., 5.00	31	15	15	30	.48	48	12	60	90
19	0827152	GGR LN2/3 LNCE+LEWS 15., 5.00	26	9	16	25	.36	127	31	158	183
20	0831152	GGR WKIE ALMOND 15., 5.00	4	2	1	3	.67	4	1	7	10
21	0832152	GGR WKIE LNCE + LEWS15., 5.00	4	1	2	3	.38	7	1	8	11
22	0833152	GGR,WASKIE L.M.V 15.0,5.00	0	0	0	0	I	0	0	0	0
23	0834152	GGR WKIE LNCE,LWS+AL15., 5.00	64	42	21	63	.67	76	19	95	158
24	0835152	GGR WKIE AL +L.M.VDE15., 5.00	10	6	3	9	.62	11	2	13	22
25	0841152	GGR,E/2,L4 M.VERDE 15.0,5.00	0	0	0	0	I	0	0	0	0
26	0842152	GGR E/2 L4 FT UNION15., 5.00	13	3	9	12	.25	17	4	21	33
27	0843152	GGR E/2 L4 F UN+MV 15., 5.00	6	3	3	6	.50	1	0	1	7
28	0851152	GGR,B,L5,W/2L4,FT/UN 15.0,5.00	0	0	0	0	I	0	0	0	0
29	0852152	GGR,B,L5,W/2L4,L+MV 15.0,5.00	0	0	0	0	I	0	0	0	0
30	1001152	UINTA WASATCH 15., 5.00	56	24	32	56	.43	135	33	168	224
31	1002152	UINTA BARREN 15., 5.00	68	29	38	67	.43	140	35	175	242
32	1003152	UINTA CUALY 15., 5.00	9	4	4	8	.54	46	11	57	65
33	1004152	UINTA , CASTLEGATE 15.0,5.00	8	2	5	7	.26	29	7	36	43
34	1005152	UINTA , COALY +CASGT 15.0,5.00	17	7	9	16	.45	27	6	33	49
35	1006152	UINTA WASATCH CUALY 15., 5.00	40	21	18	39	.55	43	10	53	92
36	1007152	UINTA WASATCH BARREN15., 5.00	88	37	47	84	.44	117	29	146	230
37	1101152	WIND R. LWR FT UNION15., 5.00	161	100	60	160	.63	856	214	1070	1230
38	1104152	W.RIVER , M.V.15000 15.0,5.00	0	0	0	0	I	0	0	0	0
39	1106152	W/R ,LA14000+MV15000 15.0,5.00	0	0	0	0	I	0	0	0	0
40	1107152	WIND R.FRONTIER MDDY15., 5.00	31	9	21	30	.32	163	40	203	233
41	1301152	ORCOKAN COZET 15., 5.00	42	19	22	41	.48	114	28	142	183
42	1302152	PICEANCE,FT UNION 15., 5.00	9	4	4	8	.47	70	17	87	95
43	1303152	PICEANCE,M V 8000 15., 5.00	63	29	33	62	.47	493	123	616	678
44	1304152	PICEANCE,COR-COZ MV 15., 5.00	44	28	15	43	.65	88	22	110	153
45	1305152	PICEANCE,FTU MV 15., 5.00	39	22	16	38	.57	56	14	70	108
46	1306152	PICEANCE,FTU COR-COZ15., 5.00	26	13	12	25	.52	53	13	66	91
47	1307152	PICEANCE,LWRCRET JNR15., 5.00	19	5	13	18	.31	113	28	141	159
48	2001152	DENVER MUDDY J 15.0,5.00	0	0	0	0	I	0	0	0	0

TABLE E-2(2)d

49	0502252	DENVER 8	15.0,5.00	26	6	22	28	.22	34	9	45	73
50	0801252	GGR LEW 1 ALMO A	15., 5.00	13	9	3	12	.71	27	6	33	45
51	0802252	GGR LEW 1 E.RS,BL	15., 5.00	24	5	18	23	.23	33	8	41	64
52	0803252	GGR LEW 1 FT UNION	15., 5.00	61	18	42	60	.30	58	14	72	132
53	0804252	GGR LEW 1 ALMD A+B	15., 5.00	56	43	13	56	.76	57	14	71	127
54	0805252	GGR LEW 1 AL A+E,R,BL	15., 5.00	159	96	62	158	.61	56	14	70	228
55	0806252	GGR LEW 1 AL B+E,R,BL	15., 5.00	164	70	93	163	.43	475	118	593	756
56	0807252	GGR LEW 1 LNCE,LEWIS	15., 5.00	115	41	73	114	.36	491	122	613	727
57	0911252	GGR S/NASH LW9 7000	15., 5.00	121	53	67	120	.44	83	20	103	223
58	0912252	GGR S/NASH LW9 9000	15., 5.00	53	26	26	52	.49	57	14	71	123
59	0813252	GGR,S/WSH, MV 9000	15.0,5.00	0	0	0	0	I	0	0	0	0
60	0814252	GGR,S/WSH, MV 11000	15.0,5.00	0	0	0	0	I	0	0	0	0
61	0815252	GGR S/W L7000+MV9000	15., 5.00	51	19	31	50	.38	39	9	48	98
62	0816252	GGR S/W MV9000+11000	15., 5.00	6	1	4	5	.24	5	1	6	11
63	0821252	GGR L2/3 ALMD A	15., 5.00	99	68	30	98	.69	99	24	123	221
64	0823252	GGR L2/3 ERK,RS,BL	15., 5.00	113	30	82	112	.27	543	135	678	790
65	0824252	GGR L2/3 FT UNION	15., 5.00	95	49	45	94	.52	194	48	242	336
66	0826252	GGR L2/3 AL B+E,RS,BL	15., 5.00	109	52	56	108	.49	362	90	452	560
67	0827252	GGR L2/3 LANCE/LEWIS	15., 5.00	116	51	64	115	.44	894	223	1117	1232
68	0831252	GGR WSKLE ALMOND	15., 5.00	16	10	5	15	.68	9	2	11	26
69	0832252	GGR WSKLE LNCE/LEWS	15., 5.00	43	6	36	42	.15	116	29	145	187
70	0833252	GGR,WASKIE L.M.V	15.0,5.00	0	0	0	0	I	0	0	0	0
71	0834252	GGR WSKLE LN/LE +AL	15., 5.00	20	13	6	19	.66	11	2	13	32
72	0835252	GGR WSKLE ALD +L.M.V	15., 5.00	68	44	23	67	.66	39	9	48	115
73	0841252	GGR,E/2,L4 M.VERDE	15.0,5.00	0	0	0	0	I	0	0	0	0
74	0842252	GGR E/2 L4 FT UNION	15., 5.00	85	21	63	84	.25	235	58	293	377
75	0843252	GGR,E/2 L4 F/UN+M.V	15.0,5.00	72	35	36	71	.49	18	4	22	93
76	0851252	GGR B.L5,W/2L4 F UNN	15., 5.00	21	5	15	20	.27	93	23	116	136
77	0852252	GGR,B,L5,W/2L4,L+MV	15.0,5.00	0	0	0	0	I	0	0	0	0
78	1001252	UINTA WASATCH	15., 5.00	81	34	46	80	.42	153	38	191	271
79	1002252	UINTA BARREN	15., 5.00	66	28	37	65	.43	112	28	140	205
80	1003252	UINTA COALY	15., 5.00	29	15	13	28	.54	53	13	66	94
81	1004252	UINTA CASTLEGATE	15., 5.00	43	18	24	42	.44	124	31	155	197
82	1005252	UINTA COALY CSILGT	15., 5.00	51	22	28	50	.45	22	5	27	77
83	1006252	UINTA WASATCH COALY	15., 5.00	130	71	58	129	.55	55	13	68	197
84	1007252	UINTA WASATCH BARREN	15., 5.00	95	40	54	94	.43	121	30	151	245
85	1101252	WIND R. LWR FT UNION	15., 5.00	230	143	86	229	.63	1002	250	1252	1481
86	1104252	W.RIVER , M.V.15000	15.0,5.00	0	0	0	0	I	0	0	0	0
87	1106252	W/RIV,L14000,MV15000	15.0,5.00	0	0	0	0	I	0	0	0	0
88	1107252	WIND R.FRONTIER MDDY	15., 5.00	92	34	57	91	.38	354	88	442	533
89	1301252	PICEANCE,COR-COZ	15., 5.00	112	56	55	111	.51	147	36	183	294
90	1302252	PICEANCE,FT UNION	15., 5.00	39	18	20	38	.47	435	108	543	581
91	1303252	PICEANCE,M V 9000	15., 5.00	156	72	83	155	.47	1867	466	2333	2488
92	1304252	PICEANCE,COR-COZ MV	15., 5.00	98	63	34	97	.65	158	39	197	294
93	1305252	PICEANCE,FTU MV	15., 5.00	51	24	26	50	.48	149	37	186	236
94	1306252	PICEANCE,FTU COR-COZ	15., 5.00	25	13	11	24	.52	30	7	37	61
95	1307252	PICEANCE,LWRCRET JUR	15., 5.00	78	23	54	77	.31	328	82	410	487
96	2001252	DENVER MUDDY J	15.0,5.00	172	118	67	185	.64	626	156	782	967
97	2422152	GGR,LEN2+3, AL B	15.0,5.00	5	2	2	4	.47	8	2	10	14
98	2425152	GGR,LEN2+3,AL A+B	15.0,5.00	15	9	5	14	.65	52	13	65	79
99	2453152	GGR,W/2L4,B,L5,FRNTR	15.0,5.00	3	0	2	2	.25	8	2	10	12
100	2454152	GGR,W/2L4,B,L5,MVL+F	15.0,5.00	5	1	3	4	.25	3	0	3	7
101	2455152	GGR,B,L5,W/2L4,FU+MVL	15.0,5.00	3	1	1	2	.34	2	0	2	4
102	2502152	WIND R. LANCE 9000	15.0,5.00	11	7	3	10	.64	46	11	57	67
103	2503152	WIND R. LANCE 14000	15.0,5.00	3	1	1	2	.44	6	1	7	9
104	2505152	WIND R. LFU +LN9000	15.0,5.00	51	35	15	50	.69	121	30	151	201
105	2422252	GGR,LEN2+3, AL B	15.0,5.00	22	9	12	21	.45	32	8	40	61
106	2425252	GGR,LEN2+3,AL A+B	15.0,5.00	96	62	33	95	.65	149	37	186	281
107	2453252	GGR,W/2L4,B,L5,FRNTR	15.0,5.00	61	26	34	60	.43	125	31	156	216
108	2454252	GGR,W/2L4,B,L5,MVL+F	15.0,5.00	27	11	15	26	.43	12	3	15	41
109	2455252	GGR,W/2L4,B,L5,FU+MVL	15.0,5.00	10	3	6	9	.34	21	5	26	35
110	2502252	WIND R. LANCE 9000	15.0,5.00	55	30	24	54	.56	344	86	430	484
111	2503252	WIND R. LANCE 14000	15.0,5.00	25	10	14	24	.43	74	18	92	116
112	2505252	WIND R. LFU +LN9000	15.0,5.00	71	49	21	70	.69	274	68	342	412

TABLE E-2(2)e

ANNUAL DRILLING SCHEDULE

	PROSPECT	YEAR	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
1	DENVER B	15.0,5.00	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	GGR LEWIN 1 ALMD A	15.,5.00	6	6	6	6	6	6	6	0	0	0	0	0	0	0	0	0	0	0	0	0
3	GGR,LEW 1, E,R,S,B	15.0,5.00	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4	GGR LEWIN 1 FT UNION	15.,5.00	0	0	0	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0
5	GGR LEWIN 1 ALMD A^B	15.,5.00	19	19	19	19	19	19	19	11	7	7	3	0	0	0	0	0	0	0	0	0
6	GGR LN 1 AL A^E,RS,B	15.,5.00	5	3	5	3	5	19	17	13	9	5	1	0	0	0	0	0	0	0	0	0
7	GGR LN 1 AL B+E,RS,B	15.,5.00	12	12	12	12	12	24	22	17	12	7	4	0	0	0	0	0	0	0	0	0
8	GGR LN 1 AL LAN,LES	15.,5.00	26	26	26	26	26	53	47	37	26	15	5	0	0	0	0	0	0	0	0	0
9	GGR S/WASH LENS 7000	15.,5.00	0	0	0	0	2	2	2	8	8	5	5	0	0	0	0	0	0	0	0	0
10	GGR S/WASH LENS 9000	15.,5.00	0	0	0	0	0	0	0	2	2	2	2	0	0	0	0	0	0	0	0	0
11	GGR,S/WSH, MV 9000	15.0,5.00	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	GGR,S/WSH, MV 11000	15.0,5.00	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13	GGR S/W L7000+MV9000	15.,5.00	0	0	0	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0
14	GGR,S/WSH,M9000,11000	15.0,5.00	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15	GGR LN 2/3 ALMOND A	15.,5.00	0	0	2	2	2	4	4	4	2	2	2	0	0	0	0	0	0	0	0	0
16	GGR LN 2/3 E,RS,BL	15.,5.00	0	0	0	0	0	0	4	4	4	4	4	0	0	0	0	0	0	0	0	0
17	GGR LN 2/3 FT UNION	15.,5.00	0	0	0	0	2	2	2	2	2	2	1	0	0	0	0	0	0	0	0	0
18	GGR LN2/3 AL B+E,R,B	15.,5.00	0	0	2	8	14	14	14	14	11	5	2	0	0	0	0	0	0	0	0	0
19	GGR LN2/3 LNCE+LEWS	15.,5.00	0	7	14	21	21	21	21	21	28	21	7	0	0	0	0	0	0	0	0	0
20	GGR WKIE ALMOND	15.,5.00	0	0	0	0	3	3	3	3	0	0	0	0	0	0	0	0	0	0	0	0
21	GGR WKIE LNCE + LEWS	15.,5.00	0	0	0	0	0	0	3	3	3	3	0	0	0	0	0	0	0	0	0	0
22	GGR,WASKIE L.M.V	15.0,5.00	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
23	GGR WKIE LNCE,L4S+AL	15.,5.00	7	12	12	17	24	24	22	17	12	7	0	0	0	0	0	0	0	0	0	0
24	GGR WKIE AL +L.M.VDE	15.,5.00	0	0	0	2	2	4	4	4	2	2	0	0	0	0	0	0	0	0	0	0
25	GGR,E/2,L4 M.VERDE	15.0,5.00	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
26	GGR E/2 L4 FT UNION	15.,5.00	0	0	0	2	2	5	7	7	5	2	0	0	0	0	0	0	0	0	0	0
27	GGR E/2 L4 F UN+MV	15.,5.00	0	0	0	0	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0
28	GGR,B,L5,W/2L4,FT/UN	15.0,5.00	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
29	GGR,B,L5,W/2L4,L+MV	15.0,5.00	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
30	UINTA WASATCH	15.,5.00	12	16	24	32	32	32	28	24	16	8	0	0	0	0	0	0	0	0	0	0
31	UINTA BARREN	15.,5.00	10	14	25	35	35	35	32	25	17	10	0	0	0	0	0	0	0	0	0	0
32	UINTA COALY	15.,5.00	0	7	14	14	14	7	7	0	0	0	0	0	0	0	0	0	0	0	0	0
33	UINTA , CASTLEGATE	15.0,5.00	0	5	5	11	11	5	5	0	0	0	0	0	0	0	0	0	0	0	0	0
34	UINTA , COALY +CASGT	15.0,5.00	0	3	3	9	9	9	9	6	3	0	0	0	0	0	0	0	0	0	0	0
35	UINTA WASATCH COALY	15.,5.00	7	11	16	21	16	11	7	2	0	0	0	0	0	0	0	0	0	0	0	0
36	UINTA WASATCH BARREN	15.,5.00	13	21	31	37	37	34	26	18	10	2	0	0	0	0	0	0	0	0	0	0
37	WIND R. LWR FT UNION	15.,5.00	76	91	152	191	191	145	137	107	76	45	15	0	0	0	0	0	0	0	0	0
38	W.RIVER , M.V.15000	15.0,5.00	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
39	W/R ,LA14000+MV15000	15.0,5.00	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
40	WIND R.FRONTIER MDDY	15.,5.00	22	22	38	45	38	30	22	15	0	0	0	0	0	0	0	0	0	0	0	0
41	ORCURAN COZET	15.,5.00	8	8	30	30	30	26	26	17	4	0	0	0	0	0	0	0	0	0	0	0
42	PICEANCE,FT UNION	15.,5.00	10	10	10	10	10	10	10	10	10	0	0	0	0	0	0	0	0	0	0	0
43	PICEANCE,M V 8000	15.,5.00	21	53	75	75	97	97	86	64	53	53	0	0	0	0	0	0	0	0	0	0
44	PICEANCE,COR-COZ MV	15.,5.00	7	17	17	17	24	24	21	14	7	3	0	0	0	0	0	0	0	0	0	0
45	PICEANCE,FTU MV	15.,5.00	2	5	8	13	19	19	13	11	8	5	0	0	0	0	0	0	0	0	0	0
46	PICEANCE,FTU COR-COZ	15.,5.00	3	7	10	17	17	14	10	7	3	0	0	0	0	0	0	0	0	0	0	0
47	PICEANCE,LWRCRET JNR	15.,5.00	0	0	8	16	24	24	24	24	16	8	0	0	0	0	0	0	0	0	0	0
48	DENVER MUDDY J	15.0,5.00	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
49	DENVER B	15.0,5.00	0	0	0	0	0	0	2	2	2	2	2	5	5	5	5	5	5	8	8	8
50	GGR LEW 1 ALMD A	15.,5.00	0	0	0	0	0	0	0	3	3	3	3	3	3	3	3	3	3	3	3	3
51	GGR LEW 1 E.RS,BL	15.,5.00	0	0	0	0	0	0	0	0	2	2	2	2	2	5	5	8	8	8	8	8

TABLE E-2(2)f

52	GGR LEW 1 FT UNION	15.,	5.00	0	0	0	0	0	0	2	2	2	4	4	4	10	10	15	15	15	15	15	15
53	GGR LEW 1 ALMD A+B	15.,	5.00	0	0	0	0	0	0	0	4	6	6	9	11	11	11	11	11	11	11	11	9
54	GGR LEW 1 AL A+E,R,8	15.,	5.00	0	0	0	0	0	0	1	4	7	10	12	21	21	21	21	21	21	21	21	20
55	GGR LEW 1 AL B+E,R,8	15.,	5.00	0	0	0	0	0	0	4	13	23	32	60	69	69	69	69	69	69	69	69	69
56	GGR LEW 1 LNCE,LEWIS	15.,	5.00	0	0	0	0	0	0	6	19	31	44	57	63	63	63	63	63	63	63	63	63
57	GGR S/NASH LWS 7000	15.,	5.00	0	0	0	0	0	0	1	9	9	18	18	18	18	18	18	18	18	18	18	18
58	GGR S/NASH LWS 9000	15.,	5.00	0	0	0	0	0	0	0	0	2	4	11	11	11	11	11	11	11	11	11	11
59	GGR,S/WSH, MV 9000	15.0,	5.00	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
60	GGR,S/WSH, MV 11000	15.0,	5.00	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
61	GGR S/W L7000+MV9000	15.,	5.00	0	0	0	0	0	0	0	0	1	1	7	9	9	9	9	9	9	9	9	9
62	GGR S/W MV9000+L1000	15.,	5.00	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	2	2	2	2	2
63	GGR L2/3 ALMD A	15.,	5.00	0	0	0	0	0	0	0	0	4	4	11	17	17	22	22	22	22	22	22	22
64	GGR L2/3 ERK,RS,8L	15.,	5.00	0	0	0	0	0	0	0	6	6	6	11	17	17	65	65	84	84	97	97	97	97
65	GGR L2/3 FT UNION	15.,	5.00	0	0	0	0	0	0	0	3	7	7	19	19	38	38	38	38	38	38	38	38
66	GGR L2/3 AL B+E,RS,8	15.,	5.00	0	0	0	0	0	0	5	5	15	25	46	51	51	51	51	51	51	51	51	51
67	GGR L2/3 LANCE/LEWIS	15.,	5.00	0	0	0	0	0	0	10	31	53	74	106	106	106	106	106	106	106	106	106	106
68	GGR WSKLE ALMOND	15.,	5.00	0	0	0	0	0	0	0	0	3	3	3	3	3	3	1	1	0	0	0	0
69	GGR WSKLE LNCE/LEWS	15.,	5.00	0	0	0	0	0	0	0	0	4	4	8	8	8	21	21	21	21	21	21	21
70	GGR,WASKIE L.M.V	15.0,	5.00	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
71	GGR WSKLE LN/LE +AL	15.,	5.00	0	0	0	0	0	0	1	5	8	11	6	0	0	0	0	0	0	0	0	0
72	GGR WSKLE ALD +L.M.V	15.,	5.00	0	0	0	0	0	0	0	1	3	5	8	12	17	17	17	13	10	6	3	0
73	GGR,E/2,L4 M.VERDE	15.0,	5.00	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
74	GGR E/2 L4 FT UNION	15.,	5.00	0	0	0	0	0	0	0	4	8	8	13	22	31	44	44	44	44	40	35	22	13
75	GGR,E/2 L4 F/UN+M.V	15.0,	5.00	0	0	0	0	0	0	0	1	1	2	2	6	6	9	9	9	9	9	9	9	9
76	GGR 8.L5,W/2L4 F UNN	15.,	5.00	0	0	0	0	0	0	0	0	0	0	0	6	6	6	6	6	13	13	13	32	32
77	GGR,8,L5,W/2L4,L+MV	15.0,	5.00	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
78	UINTA WASATCH	15.,	5.00	0	0	0	0	0	0	0	3	6	13	20	20	23	23	16	16	16	16	26	33	33
79	UINTA BARREN	15.,	5.00	0	0	0	0	0	0	0	3	9	15	21	15	15	15	15	15	15	15	15	15	15
80	UINTA COALY	15.,	5.00	0	0	0	3	3	3	6	6	6	9	9	9	9	9	9	6	6	3	0	0	0
81	UINTA CASTLEGATE	15.,	5.00	0	0	0	0	0	0	9	9	9	9	9	9	9	13	13	13	18	18	18	18	16
82	UINTA COALY CSTLGT	15.,	5.00	0	0	0	1	3	4	4	7	7	7	7	4	4	3	3	3	3	3	3	3	3
83	UINTA WASATCH COALY	15.,	5.00	0	0	0	0	1	4	7	10	13	15	15	15	15	15	15	15	15	15	10	7	4
84	UINTA WASATCH BARREN	15.,	5.00	0	0	0	0	0	0	2	2	10	18	23	18	18	18	18	18	18	18	18	18	18
85	WIND R. LNA FT UNION	15.,	5.00	0	0	0	0	0	0	0	12	38	64	90	116	128	128	128	128	128	128	128	128	128
86	W.RIVER , M.V.15000	15.0,	5.00	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
87	W/RIV,L14000,MV15000	15.0,	5.00	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
88	WIND R.FRONTIER MUDDY	15.,	5.00	0	0	0	0	5	11	17	23	29	40	40	40	40	40	40	40	40	40	23	17	
89	PICEANCE,COR-COZ	15.,	5.00	0	0	0	0	0	0	0	2	7	10	10	26	26	26	26	26	26	26	25	26	
90	PICEANCE,FT UNION	15.,	5.00	0	0	0	0	0	0	0	14	14	29	29	29	29	44	44	44	59	59	59	59	59
91	PICEANCE,M V 8000	15.,	5.00	0	0	0	0	0	0	0	15	47	63	63	175	175	207	207	255	255	255	255	255	255
92	PICEANCE,COR-COZ MV	15.,	5.00	0	0	0	0	0	0	0	3	9	15	21	30	30	30	30	27	27	21	21	15	15
93	PICEANCE,FTU MV	15.,	5.00	0	0	0	0	0	0	0	4	14	18	32	32	32	32	23	18	14	4	4	0	0
94	PICEANCE,FTU COR-COZ	15.,	5.00	0	0	0	0	0	0	0	2	7	10	10	10	7	5	5	2	2	0	0	0	0
95	PICEANCE,LWRCRET JUR	15.,	5.00	0	0	0	0	0	0	0	6	18	25	31	37	37	37	37	37	43	43	43	43	43
96	DENVER MUDDY J	15.0,	5.00	0	0	0	0	0	0	0	5	5	28	28	28	56	56	56	56	112	112	140	140	140
97	GGR,LEN2+3, AL B	15.0,	5.00	0	0	0	0	0	0	0	3	3	3	3	3	0	0	0	0	0	0	0	0	0
98	GGR,LEN2+3,AL A+B	15.0,	5.00	0	0	0	0	5	10	10	16	16	10	5	0	0	0	0	0	0	0	0	0	0
99	GGR,W/2L4,B,L5,FRNTR	15.0,	5.00	0	0	0	0	0	0	0	0	4	4	4	0	0	0	0	0	0	0	0	0	0
100	GGR,W/2L4,B,L5,MVL+F	15.0,	5.00	0	0	0	0	0	0	0	1	1	1	1	1	0	0	0	0	0	0	0	0	0
101	GGR,B,L5,W/2L4,FU+MVL	15.0,	5.00	0	0	0	0	0	0	0	2	0	2	0	2	0	0	0	0	0	0	0	0	0
102	WIND R. LANCE 9000	15.0,	5.00	0	0	0	0	0	0	7	7	21	21	14	7	0	0	0	0	0	0	0	0	0
103	WIND R. LANCE 14000	15.0,	5.00	0	0	0	0	0	0	3	3	3	3	0	0	0	0	0	0	0	0	0	0	0
104	WIND R. LFU +LN9000	15.0,	5.00	3	15	19	26	26	26	22	19	15	11	7	0	0	0	0	0	0	0	0	0	0
105	GGR,LEN2+3, AL B	15.0,	5.00	0	0	0	0	0	0	0	2	2	2	2	2	5	5	5	5	5	5	5	5	5
106	GGR,LEN2+3,AL A+B	15.0,	5.00	0	0	0	0	0	0	2	2	5	8	11	14	29	29	29	29	29	29	29	29	29
107	GGR,W/2L4,B,L5,FRNTR	15.0,	5.00	0	0	0	0	0	0	0	0	0	0	3	3	10	17	17	24	24	24	24	32	32
108	GGR,W/2L4,B,L5,MVL+F	15.0,	5.00	0	0	0	0	0	0	0	1	3	3	3	3	3	3	3	3	3	3	3	3	3
109	GGR,W/2L4,B,L5,FU+MVL	15.0,	5.00	0	0	0	0	0	0	0	0	3	0	3	0	3	0	3	3	3	3	3	3	3
110	WIND R. LANCE 9000	15.0,	5.00	0	0	0	0	0	0	0	8	17	26	35	44	44	44	44	44	44	44	44	44	44
111	WIND R. LANCE 14000	15.0,	5.00	0	0	0	0	0	0	0	0	4	4	4	4	8	9	9	14	14	14	14	14	14
112	WIND R FU +LN9000	15.0,	5.00	0	0	0	0	0	0	5	11	17	23	29	40	40	40	40	40	40	40	23	17	
	TOTAL WELLS IN EACH YEAR			269	390	587	735	799	812	889	974	1061	1081	1222	1269	1439	1439	1509	1593	1583	1604	1575	1545

TABLE E-2(2)g

INVESTMENT REQUIREMENTS AND RESERVE ADDITIONS

YEAR	INVESTMENT (MM$)	GAS RESERVES ADDED (BCF)	CUMMULATIVE GAS RESERVES
1	265.5	494.2	494.2
2	395.3	765.0	1259.2
3	561.9	1107.2	2366.4
4	709.8	1403.0	3769.4
5	796.8	1556.5	5325.9
6	861.6	1652.6	6978.4
7	1006.7	1805.0	8783.4
8	1176.5	1982.2	10765.6
9	1344.4	2165.9	12931.6
10	1441.0	2273.6	15205.1
11	1717.8	2484.1	17689.3
12	1803.1	2596.4	20285.7
13	2065.3	2886.5	23172.2
14	2068.9	2845.2	26017.4
15	2184.0	2960.8	28978.2
16	2241.2	2990.5	31968.7
17	2215.0	2910.4	34879.2
18	2210.2	2875.5	37754.7
19	2162.7	2774.6	40529.3
20	2113.1	2676.3	43205.7
	29340.8	TOTAL INVESTMENT	

TABLE E-2(2)h

CASH FLOW AND PRODUCTION SUMMARY

YEAR	ANNUAL CASH FLOW (MM$)	CUMUL. CASH FLOW (MM$)	ANNUAL NGL PRODN (MMB)	CUMUL. NGL PRODN (MMB)	ANNUAL GAS PRODN (BCF)	CUMUL. GAS PRODN (BCF)	ANNUAL GAS PRODN (BCF EQ1)	CUMUL. GAS PRODN (BCF EQ1)
1	-.7603	-.7603	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2	-11.4197	-12.1801	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
3	-54.7674	-66.9475	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
4	-34.3965	-101.3440	.5529	.5529	25.8706	25.8706	29.0775	29.0775
5	.7943	-100.5497	1.5832	2.1361	75.8064	101.6771	84.9891	114.0667
6	117.3817	16.8320	3.1468	5.2829	155.1063	256.7834	173.3577	287.4243
7	272.8372	289.6692	5.0467	10.3296	254.9245	511.7079	284.1954	571.5197
8	459.0598	748.7290	7.2000	17.5296	367.0286	878.7365	408.7887	980.4084
9	661.8994	1410.6284	9.4623	26.9920	481.0868	1359.8232	535.9682	1515.3766
10	854.3706	2264.9990	11.6531	38.6451	588.8596	1948.6828	656.4476	2172.8242
11	1037.2843	3302.2833	14.0154	52.6605	700.9589	2649.6417	782.2484	2955.0725
12	1250.0085	4552.2918	16.6474	69.3078	822.4046	3472.0464	918.9593	3874.0318
13	1464.2699	6016.5616	19.3686	88.6764	945.7564	4417.8028	1058.0943	4932.1261
14	1677.8995	7694.4611	22.2125	110.8890	1067.5795	5485.3823	1196.4121	6128.5383
15	1865.7743	9560.2354	25.1622	136.0511	1190.7882	6676.1705	1336.7288	7465.2670
16	2108.4265	11668.6620	28.3403	164.3914	1320.7884	7996.9589	1485.1621	8950.4291
17	2334.2093	14002.8713	31.3874	195.7788	1443.8599	9440.8188	1625.9068	10575.3359
18	2573.4918	16576.3631	34.3132	230.0921	1562.3634	11003.1822	1761.3802	12337.7161
19	2799.4021	19375.7653	36.9189	267.0109	1672.3864	12675.5686	1886.5159	14224.2321
20	3012.7378	22388.5031	39.2367	306.2476	1772.4647	14448.0333	2000.0375	16224.2695
21	3215.6909	25604.1940	41.2517	347.4993	1861.2350	16309.2684	2100.4947	18324.7642
22	3445.7864	29049.9804	42.8830	390.3823	1935.0764	18244.3447	2183.7976	20508.5619
23	3840.1994	32890.1798	44.1827	434.5650	1995.7287	20240.0734	2251.9886	22760.5504
24	3860.8822	36751.0621	42.1187	476.6837	1909.1603	22149.2336	2153.4486	24913.9991
25	3776.0426	40527.1047	38.7251	515.4088	1765.5198	23914.7535	1990.1256	26904.1246
26	3491.5121	44018.6167	34.7701	550.1789	1596.1360	25510.8895	1797.8024	28701.9271
27	3198.3474	47216.9641	31.3471	581.5260	1448.5772	26959.4667	1630.3902	30332.3173
28	2928.9187	50145.8829	28.5226	610.0486	1326.0998	28285.5665	1491.5311	31823.8484
29	2704.8442	52850.7271	26.1818	636.2304	1223.4145	29508.9810	1375.2690	33199.1175
30	2506.9796	55357.7067	24.1290	660.3595	1132.5130	30641.4940	1272.4614	34471.5789
31	2325.4393	57683.1461	22.2797	682.6392	1049.9098	31691.4038	1179.1323	35650.7112
32	2157.2220	59840.3681	20.6148	703.2540	974.8430	32666.2468	1094.4091	36745.1203
33	2002.5798	61842.9479	19.1332	722.3873	907.4462	33573.6930	1018.4189	37763.5392
34	1861.4877	63704.4356	17.8192	740.2065	847.2002	34420.8933	950.5517	38714.0908
35	1733.7781	65438.2137	16.6432	756.8497	792.9405	35213.8338	889.4712	39603.5620
36	1617.6875	67055.9012	15.5787	772.4284	743.5190	35957.3528	833.8757	40437.4377
37	1511.4313	68567.3325	14.6076	787.0360	698.1903	36655.5431	782.9144	41220.3521
38	1412.2854	69979.6180	13.7115	800.7476	656.1354	37311.6785	735.6623	41956.0143
39	1318.9337	71298.5516	12.8788	813.6264	616.7765	37928.4550	691.4737	42647.4880
40	1233.6352	72532.1868	12.0993	825.7257	579.5919	38508.0469	649.7679	43297.2559
41	1153.1638	73685.3506	11.3632	837.0889	544.2941	39052.3410	610.2005	43907.4565
42	1076.1562	74761.5068	10.6622	847.7511	510.3203	39562.6613	572.1611	44479.6176
43	1002.6525	75764.1593	9.9946	857.7457	477.7075	40040.3688	535.6764	45015.2940
44	932.8353	76696.9946	9.3592	867.1049	446.5820	40486.9508	500.8655	45516.1594
45	867.1225	77564.1171	8.7623	875.8673	417.1410	40904.0918	467.9625	45984.1219
46	804.4262	78368.5433	6.1916	884.0589	388.9296	41293.0214	436.4410	46420.5629
47	744.5610	79113.1044	7.6461	891.7049	361.6678	41654.6892	406.2149	46826.7778
48	688.0188	79801.1232	7.1324	898.8373	336.1729	41991.0622	377.5407	47204.3185
49	634.9821	80436.1053	6.6500	905.4873	311.9776	42303.0397	350.5473	47554.8658
50	584.5428	81020.6481	6.1938	911.6811	288.8349	42591.8746	324.7589	47879.6247
51	532.0485	81552.6966	5.7117	917.3928	264.2863	42856.1608	297.4142	48177.0390
52	480.7717	82033.4683	5.2334	922.6262	240.0493	43096.2102	270.4030	48447.4420
53	430.2421	82463.7103	4.7587	927.3849	215.7977	43312.0079	243.3982	48690.8402
54	380.9014	82844.6117	4.2867	931.6716	191.8810	43503.8888	216.7438	48907.5840
55	332.4610	83177.0727	3.8096	935.4812	168.3436	43672.2324	190.4393	49098.0233
56	285.8013	83462.8741	3.3339	938.8151	145.6772	43817.9096	165.0136	49263.0369
57	243.4059	83706.2800	2.8898	941.7048	124.9423	43942.8519	141.7029	49404.7398
58	206.4798	83912.7598	2.4408	944.1956	106.7543	44049.6062	121.2019	49525.9418
59	174.9694	84087.7292	2.1422	946.3378	91.0606	44140.6668	103.4852	49629.4271
60	147.6145	84235.3438	1.8365	948.1743	77.3864	44218.0532	88.0363	49717.4634
61	125.1848	84360.5285	1.5809	949.7552	66.0851	44284.1383	75.2542	49792.7176
62	105.6014	84466.1299	1.3550	951.1102	56.1082	44340.2465	63.9671	49856.6847
63	85.8973	84552.0272	1.1203	952.2305	45.9740	44386.2205	52.4715	49909.1562
64	68.4312	84620.4584	.9063	953.1368	36.8803	44423.1008	42.1369	49951.2931
65	52.8574	84673.3158	.7098	953.8465	28.7174	44451.8183	32.8342	49984.1272
66	39.9085	84713.2243	.5391	954.3856	21.7658	44473.5841	24.8926	50009.0198
67	28.2077	84741.4319	.3827	954.7684	15.4667	44489.0507	17.6869	50026.7067
68	17.5786	84759.0106	.2407	955.0091	9.6805	44498.7313	11.0737	50037.7804
69	8.3647	84767.3753	.1144	955.1230	4.6023	44503.3335	5.2660	50043.0464

44503. BCF--MAX GAS PRODUCED IN SCENARIO

TABLE E-2(2)i

ECONOMIC SUMMARY

PROFIT INDICATORS

DISCOUNTED PRESENT WORTH AT 15.0 PCT. (MM$)	4324.52018
DCF RATE OF RETURN (PERCENT)	89.60
PAYOUT TIME (YEARS)	4.86
PROFIT PER INVESTMENT ($/$)	2.889
MAX. UNRECOVERED INVESTMENT (MM$)	101.3440
NET CASH RECOVERY AFTER TAX (MM$)	84767.3753
EXPLORATION EXPENDITURE (MM$)	8119.6810
PRODUCTION INVESTMENT (MM$)	21818.1945
TOTAL INVESTMENT (MM$)	29340.8198
OPERATING EXPENSE (MM$)	10941.8670

TABLE E-2(3)a

Standard Scenario at $5.00 and 15%
Base and Advanced Technologies--Western U.S.

	YEAR OF DEVELOPMENT			1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	
	LOCATION OF PROSPECTS--																							
1	1101152	WESTERN INTERMED	15., 5.00	5	5	6	6	10	13	19	20	20	20	0	0	0	0	0	0	0	0	0	0	124
2	1107152	WESTERN SHALLOW	15., 5.00	15	15	15	15	17	19	23	25	25	25	0	0	0	0	0	0	0	0	0	0	194
3	1301152	WESTERN INTERMED	15., 5.00	9	9	9	9	10	11	8	8	8	8	0	0	0	0	0	0	0	0	0	0	89
4	1302152	WESTERN INTERMED	15., 5.00	5	5	5	5	5	6	6	6	5	4	0	0	0	0	0	0	0	0	0	0	52
5	1303152	WESTERN INTERMED	15., 5.00	5	5	5	5	6	7	7	8	8	8	0	0	0	0	0	0	0	0	0	0	64
6	1307152	WESTERN INTERMED	15., 5.00	13	13	13	13	13	16	12	12	12	12	0	0	0	0	0	0	0	0	0	0	129
7	1101252	WESTERN INTERMED	15., 5.00	0	0	0	0	3	3	4	3	3	3	7	8	9	10	10	10	10	10	10	10	113
8	1107252	WESTERN SHALLOW	15., 5.00	0	0	0	0	18	18	18	18	20	20	10	10	10	10	10	10	10	10	10	10	212
9	1301252	WESTERN INTERMED	15., 5.00	0	0	0	0	2	6	9	10	10	12	10	10	10	10	10	10	10	10	10	10	149
10	1302252	WESTERN INTERMED	15., 5.00	0	0	0	0	0	1	2	3	5	6	8	8	8	8	9	9	9	9	9	9	103
11	1303252	WESTERN INTERMED	15., 5.00	0	0	0	0	0	0	1	2	2	2	5	7	7	7	7	7	7	7	7	7	75
12	1307252	WESTERN INTERMED	15., 5.00	0	0	0	6	7	11	14	25	25	20	20	20	17	17	17	17	17	17	17	17	284
13	2502152	WESTERN DEEP	15., 5.00	0	1	1	1	1	2	3	1	0	0	0	0	0	0	0	0	0	0	0	0	10
14	2503152	WESTERN DEEP	15., 5.00	0	1	1	1	1	2	3	1	0	0	0	0	0	0	0	0	0	0	0	0	10
15	2502252	WESTERN DEEP	15., 5.00	0	0	0	0	0	2	2	4	5	5	5	5	5	5	5	5	5	5	5	5	68
16	2503252	WESTERN DEEP	15., 5.00	0	0	0	0	0	2	2	4	6	6	6	6	6	6	6	6	6	6	6	6	80

TABLE E-2(3)b

SUMMARY OF WELL REQUIREMENTS

	CASE	LOCATION OF PROSPECT		NO. PROSP.	WILDCAT WELLS			W/C SUCCESS RATIO	DEVELOPMENT WELLS			TOTAL ALL WELLS
					PROD.	DRY	TOTAL		PROD.	DRY	TOTAL	
1	1101152	WESTERN INTERMED	15., 5.00	124	77	46	123	.63	659	164	823	946
2	1107152	WESTERN SHALLOW	15., 5.00	194	61	132	193	.32	1025	256	1281	1474
3	1301152	WESTERN INTERMED	15., 5.00	89	42	46	88	.48	242	60	302	390
4	1302152	WESTERN INTERMED	15., 5.00	52	24	27	51	.47	405	101	506	557
5	1303152	WESTERN INTERMED	15., 5.00	64	29	34	63	.47	501	125	626	689
6	1307152	WESTERN INTERMED	15., 5.00	129	39	89	128	.31	767	191	958	1086
7	1101252	WESTERN INTERMED	15., 5.00	113	70	42	112	.63	492	123	615	727
8	1107252	WESTERN SHALLOW	15., 5.00	212	79	132	211	.38	815	203	1018	1229
9	1301252	WESTERN INTERMED	15., 5.00	149	75	73	148	.51	195	48	243	391
10	1302252	WESTERN INTERMED	15., 5.00	103	48	54	102	.47	1150	287	1437	1539
11	1303252	WESTERN INTERMED	15., 5.00	75	34	40	74	.47	897	224	1121	1195
12	1307252	WESTERN INTERMED	15., 5.00	264	86	197	283	.31	1195	298	1493	1776
13	2502152	WESTERN DEEP	15., 5.00	10	6	3	9	.64	42	10	52	61
14	2503152	WESTERN DEEP	15., 5.00	10	4	5	9	.44	21	5	26	35
15	2502252	WESTERN DEEP	15., 5.00	68	38	29	67	.56	426	106	532	599
16	2503252	WESTERN DEEP	15., 5.00	80	34	45	79	.43	222	55	277	356

TABLE E-2(3)c

ANNUAL DRILLING SCHEDULE

	PROSPECT		YEAR	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
1	WESTERN INTERMED	15.,	5.00	38	38	45	45	76	99	145	152	152	152	0	0	0	0	0	0	0	0	0	0
2	WESTERN SHALLOW	15.,	5.00	114	114	114	114	129	144	175	190	190	190	0	0	0	0	0	0	0	0	0	0
3	WESTERN INTERMED	15.,	5.00	39	39	39	39	44	48	35	35	35	35	0	0	0	0	0	0	0	0	0	0
4	WESTERN INTERMED	15.,	5.00	53	53	53	53	53	64	64	64	53	43	0	0	0	0	0	0	0	0	0	0
5	WESTERN INTERMED	15.,	5.00	53	53	53	53	64	75	75	86	86	86	0	0	0	0	0	0	0	0	0	0
6	WESTERN INTERMED	15.,	5.00	104	104	104	104	104	128	96	96	96	96	0	0	0	0	0	0	0	0	0	0
7	WESTERN INTERMED	15.,	5.00	0	0	0	0	19	19	25	19	19	19	45	51	58	64	64	64	64	64	64	64
8	WESTERN SHALLOW	15.,	5.00	0	0	0	0	104	104	104	104	116	116	58	58	58	58	58	58	58	58	58	58
9	WESTERN INTERMED	15.,	5.00	0	0	0	0	5	15	23	26	26	31	26	26	26	26	26	26	26	26	26	26
10	WESTERN INTERMED	15.,	5.00	0	0	0	0	0	14	29	44	74	89	119	119	119	119	134	134	134	134	134	134
11	WESTERN INTERMED	15.,	5.00	0	0	0	0	0	0	15	31	31	31	79	111	111	111	111	111	111	111	111	111
12	WESTERN INTERMED	15.,	5.00	0	0	0	37	43	68	67	156	156	125	125	125	106	106	106	106	106	106	106	106
13	WESTERN DEEP	15.,	5.00	0	7	7	7	7	14	21	7	0	0	0	0	0	0	0	0	0	0	0	0
14	WESTERN DEEP	15.,	5.00	0	3	3	3	3	7	11	3	0	0	0	0	0	0	0	0	0	0	0	0
15	WESTERN DEEP	15.,	5.00	0	0	0	0	0	17	17	35	44	44	44	44	44	44	44	44	44	44	44	44
16	WESTERN DEEP	15.,	5.00	0	0	0	0	0	9	9	18	28	28	28	28	28	28	28	28	28	28	28	26
	TOTAL WELLS IN EACH YEAR			401	411	418	455	651	825	931	1066	1106	1085	524	562	550	556	571	571	571	571	571	571

TABLE E-2(3)d

INVESTMENT REQUIREMENTS AND RESERVE ADDITIONS

YEAR	INVESTMENT (MM$)	GAS RESERVES ADDED (BCF)	CUMMULATIVE GAS RESERVES
1	235.9	353.9	353.9
2	248.9	365.1	719.0
3	254.7	374.0	1092.9
4	286.1	404.0	1497.0
5	401.2	629.8	2126.7
6	551.5	810.2	2936.9
7	641.6	944.9	3881.8
8	765.3	1081.6	4963.4
9	802.0	1121.8	6085.3
10	784.7	1114.1	7199.3
11	508.7	624.8	7824.1
12	563.5	693.0	8517.1
13	554.2	688.6	9205.7
14	560.5	699.2	9904.9
15	570.7	712.1	10617.0
16	570.7	712.1	11329.0
17	570.7	712.1	12041.1
18	570.7	712.1	12753.2
19	570.7	712.1	13465.3
20	570.7	712.1	14177.3
	10583.3	TOTAL INVESTMENT	

TABLE E-2(3)e

CASH FLOW AND PRODUCTION SUMMARY

YEAR	ANNUAL CASH FLOW (MM$)	CUMUL. CASH FLOW (MM$)	ANNUAL NGL PRODN (MMB)	CUMUL. NGL PRODN (MMB)	ANNUAL GAS PRODN (BCF)	CUMUL. GAS PRODN (BCF)	ANNUAL GAS PRODN (BCF EQ1)	CUMUL. GAS PRODN (BCF EQ1)
1	-.6772	-.6772	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2	-9.5571	-10.2343	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
3	-25.8363	-36.0706	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
4	-23.4125	-59.4831	.1395	.1395	7.6294	7.6294	8.4383	8.4383
5	-29.6519	-89.1350	.5119	.6514	27.9570	35.5864	30.9263	39.3646
6	11.1458	-77.9892	1.0537	1.7051	57.8805	93.4669	63.9921	103.3566
7	47.6951	-30.2942	1.5533	3.2584	85.2370	178.7039	94.2463	197.6029
8	77.8509	47.5567	2.1647	5.4231	117.9057	296.6096	130.3407	328.1436
9	128.6948	176.2515	3.0113	8.4344	162.6507	459.2603	180.3161	508.4597
10	205.2781	381.5295	4.0967	12.5311	220.2426	679.7030	244.0037	752.4635
11	313.5609	695.0904	5.3226	17.8537	285.0637	964.8667	315.9347	1068.3981
12	439.3422	1134.4326	6.6266	24.4803	353.3120	1318.1787	391.7462	1460.1443
13	587.6325	1722.0651	7.8479	32.3282	418.1703	1736.3290	463.5884	1923.9327
14	697.0837	2420.2488	8.6264	40.9546	460.6957	2196.9787	510.6826	2434.5153
15	760.2476	3180.4964	8.9267	49.8813	479.1359	2676.1646	530.9722	2965.4875
16	801.7756	4010.2720	8.9291	58.8124	481.6388	3157.8034	533.4278	3498.9153
17	817.9236	4828.1956	9.0050	67.8174	487.8435	3645.6469	540.0723	4038.9876
18	833.8212	5662.0169	9.1564	76.9738	497.5803	4143.2272	550.6877	4589.6753
19	856.0618	6518.0786	9.3748	86.3486	510.5287	4653.7559	564.9025	5154.5779
20	881.0193	7400.4980	9.6090	95.9576	524.2320	5177.9879	579.7652	5734.3431
21	907.2962	8308.0822	9.8378	105.7954	537.6506	5715.6393	594.7098	6329.2528
22	944.7029	9252.7851	10.0606	115.8561	550.7193	6266.3586	609.6710	6938.9239
23	1010.2092	10262.9943	10.2796	126.1357	563.5252	6829.8838	623.8470	7561.4709
24	1032.4598	11295.4541	10.6583	136.1940	557.7843	7387.6681	611.1223	8172.5932
25	1038.9627	12334.4168	9.4189	145.6129	520.2040	7907.8721	574.6337	8747.2269
26	971.7362	13306.1530	8.5390	154.1519	473.9351	8376.8072	523.4615	9270.6884
27	876.6939	14202.8469	7.7524	161.9043	432.6470	8809.5542	477.8103	9748.4992
28	824.2523	15027.0992	7.1002	169.0045	398.7044	9208.3586	439.8656	10188.3648
29	764.0785	15791.1777	6.5634	175.5679	370.3953	9578.7539	408.4629	10597.0277
30	712.1164	16503.2941	6.0929	181.6608	345.3880	9924.1419	380.7271	10977.7548
31	664.2712	17167.5653	5.6656	187.3265	322.4914	10246.6332	355.3521	11333.1068
32	619.6304	17787.1957	5.2787	192.6052	301.6532	10548.2865	332.2699	11665.3767
33	578.5078	18365.7035	4.9323	197.5375	282.8344	10831.1208	311.4415	11976.8182
34	540.4324	18906.1359	4.6253	202.1628	265.9263	11097.0471	292.7531	12269.5713
35	505.7925	19411.9285	4.3505	206.5133	250.5051	11347.6523	275.8161	12545.4094
36	473.6119	19885.5404	4.1004	210.6137	236.2822	11583.9145	260.0648	12805.4742
37	443.5032	20329.1436	3.8713	214.4850	222.8707	11806.7912	245.3300	13050.8042
38	415.0365	20744.1801	3.6604	218.1454	210.2601	12017.0514	231.4963	13282.2945
39	388.9943	21131.1744	3.4560	221.6014	197.9961	12215.0474	218.0411	13500.3356
40	360.5607	21491.8551	3.2575	224.8589	186.0764	12401.1238	204.9698	13705.3053
41	335.3553	21827.2104	3.0650	227.9239	174.5050	12575.6289	192.2023	13897.5076
42	311.6153	22138.8257	2.8828	230.8067	163.5593	12739.1882	180.2793	14077.7869
43	289.4641	22428.2898	2.7127	233.5193	153.2820	12892.4702	169.0195	14246.8063
44	269.1396	22697.4294	2.5561	236.0754	143.7776	13036.2478	158.4028	14405.4851
45	251.6085	22949.0379	2.4238	238.4992	135.5173	13171.7650	149.5751	14555.0602
46	236.1558	23185.1937	2.3001	240.8072	128.2544	13300.0195	141.6412	14696.7015
47	221.8604	23407.0542	2.2005	243.0078	121.5076	13421.5270	134.2707	14830.9722
48	208.3871	23615.4412	2.0990	245.1068	115.1212	13536.6483	127.2953	14958.2674
49	196.0895	23811.5307	2.0020	247.1088	109.2657	13645.9140	120.8773	15079.1448
50	184.8913	23996.2220	1.9106	249.0193	103.8093	13749.7233	114.8907	15194.0355
51	170.3123	24166.5343	1.7872	250.8066	96.3925	13846.1158	106.7583	15300.7939
52	157.6547	24324.1891	1.6738	252.4803	89.7468	13935.8626	99.4546	15400.2485
53	146.3635	24470.5526	1.5707	254.0511	83.7616	14019.6242	92.8718	15493.1203
54	135.5707	24606.1293	1.4705	255.5216	77.9384	14097.5625	86.4073	15579.5276
55	124.4869	24730.6163	1.3648	256.8864	71.6387	14169.4012	79.4544	15658.9821
56	112.1626	24842.7789	1.2427	258.1291	64.9014	14234.3027	72.1042	15731.0863
57	99.1332	24941.9121	1.1076	259.2366	57.5107	14291.8133	63.9345	15795.0208
58	85.3678	25027.2799	.9612	260.1978	49.5866	14341.4000	55.1813	15850.2021
59	71.4769	25098.7569	.8114	261.0092	41.5662	14382.9662	46.2724	15896.4745
60	57.9901	25156.7470	.6647	261.6739	33.7773	14416.7435	37.5325	15934.0071
61	50.3029	25207.0498	.5008	262.1747	29.4420	14446.1854	32.8105	15967.2035
62	42.6403	25249.6901	.4964	262.7711	25.1116	14471.2970	27.9909	15995.2535
63	35.2989	25284.9891	.4153	263.1864	20.9021	14492.2992	23.3711	16018.6246
64	29.4966	25313.4857	.3386	263.5050	17.0542	14509.3133	19.0178	16037.6424
65	22.2525	25335.6982	.2677	263.7727	13.4612	14522.7746	15.0140	16052.6564
66	17.0663	25352.7645	.2063	263.9791	10.3607	14533.1353	11.5575	16064.2139
67	12.1795	25364.9441	.1484	264.1275	7.4465	14540.5818	8.3074	16072.5213
68	7.6522	25372.5963	.0940	264.2215	4.7119	14545.2937	5.2570	16077.7783
69	3.6606	25376.2568	.0450	264.2665	2.2563	14547.5500	2.5171	16080.2954

14548. BCF--MAX GAS PRODUCED IN SCENARIO

TABLE E-2(3)f

ECONOMIC SUMMARY

PROFIT INDICATORS

DISCOUNTED PRESENT WORTH AT 15.0 PCT. (MM$)	1286.33147
DCF RATE OF RETURN (PERCENT)	58.20
PAYOUT TIME (YEARS)	6.39
PROFIT PER INVESTMENT ($/$)	2.398
MAX. UNRECOVERED INVESTMENT (MM$)	89.1350
NET CASH RECOVERY AFTER TAX (MM$)	25376.2568
EXPLORATION EXPENDITURE (MM$)	1774.4831
PRODUCTION INVESTMENT (MM$)	8930.5421
TOTAL INVESTMENT (MM$)	10583.3340
OPERATING EXPENSE (MM$)	5943.6679

TABLE E-2(4)a

Standard Scenario at $5.00 and 15%
Base and Advanced Technologies--Southwest

20 YEAR DEVELOPMENT PROGRAM

	YEAR OF DEVELOPMENT			1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	
	LOCATION OF PROSPECTS--																							
1	1501152	SAN JUAN DAKOTA	15., 5.00	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	7
2	1801152	VAL VERDE SONORA	15., 5.00	1	1	2	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0	14
3	1501252	SAN JUAN DAKOTA	15., 5.00	0	0	0	0	0	1	4	5	6	6	6	6	6	6	6	6	6	6	6	6	83
4	1801252	VAL VERDE SONORA	15., 5.00	0	0	0	0	0	0	1	2	3	3	3	3	3	3	3	3	3	3	3	3	42
5	2101152	COTTON VALLEY TREND	15.0,5.00	2	4	5	6	5	5	5	5	5	5	0	0	0	0	0	0	0	0	0	0	53
6	2201152	EDWARDS LIME SW	15.0,5.00	2	4	6	8	10	5	2	0	0	0	0	0	0	0	0	0	0	0	0	0	37
7	2202152	EDWARDS LIME CENTRAL	15.0,5.00	1	2	3	4	5	3	1	0	0	0	0	0	0	0	0	0	0	0	0	0	19
8	2301152	VAL VERDE UZONA	15.0,5.00	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	2101252	COTTON VALLEY TREND	15.0,5.00	0	0	0	9	20	30	40	40	45	40	35	35	30	25	20	20	20	20	20	20	449
10	2201252	EDWARDS LIME SW	15.0,5.00	0	0	0	0	0	10	10	12	12	12	12	12	12	12	12	12	12	12	12	12	176
11	2202252	EDWARDS LIME CENTRAL	15.0,5.00	0	0	0	0	0	10	10	15	15	15	15	15	15	15	15	15	15	15	15	15	225
12	2301252	VAL VERDE UZONA	15.0,5.00	0	0	0	0	0	1	1	1	1	2	2	2	2	2	2	2	2	2	2	2	26

TABLE E-2(4)b

SUMMARY OF WELL REQUIREMENTS

	CASE	LOCATION OF PROSPECT		NO. PROSP.	WILDCAT WELLS			W/C SUCCESS RATIO	DEVELOPMENT WELLS			TOTAL ALL WELLS
					PROD.	DRY	TOTAL		PROD.	DRY	TOTAL	
1	1501152	SAN JUAN DAKOTA	15., 5.00	7	3	4	7	.49	173	43	215	223
2	1801152	VAL VERDE SONORA	15., 5.00	14	4	10	14	.28	159	39	198	212
3	1501252	SAN JUAN DAKOTA	15., 5.00	83	32	65	96	.66	1279	319	1598	1693
4	1801252	VAL VERDE SONORA	15., 5.00	42	19	37	56	.35	856	212	1068	1110
5	2101152	COTTON VALLEY TREND	15.0,5.00	34	10	25	35	.30	121	30	151	186
6	2201152	EDWARDS LIME SW	15.0,5.00	37	19	33	52	.37	67	16	83	135
7	2202152	EDWARDS LIME CENTRAL	15.0,5.00	19	7	19	26	.27	24	6	30	56
8	2301152	VAL VERDE UZONA	15.0,5.00	0	0	0	0	.11	0	0	0	0
9	2101252	COTTON VALLEY TREND	15.0,5.00	469	200	334	534	.37	1322	330	1652	2186
10	2201252	EDWARDS LIME SW	15.0,5.00	176	100	153	253	.40	208	52	260	513
11	2202252	EDWARDS LIME CENTRAL	15.0,5.00	225	125	195	320	.39	250	62	312	632
12	2301252	VAL VERDE UZONA	15.0,5.00	26	13	26	39	.33	481	120	601	640

TABLE E-2(4)c

ANNUAL DRILLING SCHEDULE

	PROSPECT	YEAR	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
1	SAN JUAN DAKOTA	15., 5.00	32	32	32	32	32	32	32	0	0	0	0	0	0	0	0	0	0	0	0	0
2	VAL VERDE SONORA	15., 5.00	19	19	19	39	39	39	39	0	0	0	0	0	0	0	0	0	0	0	0	0
3	SAN JUAN DAKOTA	15., 5.00	0	0	0	0	0	20	81	122	122	122	122	122	122	122	122	122	122	122	122	122
4	VAL VERDE SONORA	15., 5.00	0	0	0	0	0	0	79	79	79	79	79	79	79	79	79	79	79	79	79	79
5	COTTON VALLEY TREND	15.0,5.00	11	23	29	35	29	29	29	0	0	0	0	0	0	0	0	0	0	0	0	0
6	EDWARDS LIME SW	15.0,5.00	7	14	22	29	37	16	7	0	0	0	0	0	0	0	0	0	0	0	0	0
7	EDWARDS LIME CENTRAL	15.0,5.00	3	8	9	12	15	9	3	0	0	0	0	0	0	0	0	0	0	0	0	0
8	VAL VERDE OZONA	15.0,5.00	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	COTTON VALLEY TREND	15.0,5.00	0	0	0	67	149	224	299	299	314	299	262	262	224	187	149	149	149	149	149	149
10	EDWARDS LIME SW	15.0,5.00	0	0	0	0	0	29	65	35	35	35	35	35	35	35	35	35	35	35	35	35
11	EDWARDS LIME CENTRAL	15.0,5.00	6	0	0	14	14	28	28	42	42	42	42	42	42	42	42	42	42	42	42	42
12	VAL VERDE OZONA	15.0,5.00	0	0	0	0	0	24	24	24	24	49	49	49	49	49	49	49	49	49	49	49
	TOTAL WELLS IN EACH YEAR		72	94	111	228	315	452	650	601	638	626	589	589	551	514	476	476	476	476	476	476

TABLE E-2(4)d

INVESTMENT REQUIREMENTS AND RESERVE ADDITIONS

YEAR	INVESTMENT (MMI)	GAS RESERVES ADDED (BCF)	CUMMULATIVE GAS RESERVES
1	49.0	88.6	88.6
2	78.4	150.4	238.9
3	102.6	200.4	439.3
4	257.0	525.1	964.4
5	353.7	740.8	1705.2
6	520.8	1137.8	2843.1
7	658.0	1404.2	4247.3
8	679.8	1456.4	5703.7
9	717.5	1542.4	7246.1
10	693.8	1476.9	8723.0
11	656.2	1390.9	10113.9
12	656.2	1390.9	11504.8
13	616.5	1304.9	12809.7
14	580.9	1218.8	14028.5
15	543.3	1132.8	15161.3
16	543.3	1132.8	16294.1
17	543.3	1132.8	17426.9
18	543.3	1132.8	18559.7
19	543.3	1132.8	19692.5
20	543.3	1132.8	20825.2
	9881.9	TOTAL INVESTMENT	

TABLE E-2(4)e

CASH FLOW AND PRODUCTION SUMMARY

YEAR	ANNUAL CASH FLOW (MM$)	CUMUL. CASH FLOW (MM$)	ANNUAL NGL PRODN (MMB)	CUMUL. NGL PRODN (MMB)	ANNUAL GAS PRODN (BCF)	CUMUL. GAS PRODN (BCF)	ANNUAL GAS PRODN (BCF EQU)	CUMUL. GAS PRODN (BCF EQU)
1	-.2911	-.2911	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2	-2.0000	-2.3486	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
3	-9.1492	-11.6918	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
4	-18.6425	-30.7343	.0198	.0198	2.3063	2.3063	2.4213	2.4213
5	-25.4605	-56.1948	.0696	.0895	7.9409	9.9041	10.4226	12.8439
6	-49.3317	-105.5265	.1443	.2337	15.9769	25.4800	16.4137	29.2577
7	-34.4729	-139.9994	.4351	.6688	40.5345	66.0145	43.0578	68.5935
8	-12.0003	-152.0577	.9023	1.5711	74.8352	140.8496	80.4195	150.3130
9	82.6231	-70.2646	1.7736	3.4602	134.5910	275.4407	144.7778	295.1909
10	182.5951	112.4005	2.8239	6.2841	200.9663	476.4070	217.3742	512.5650
11	319.7274	432.1279	3.9225	10.1966	275.9043	752.3112	298.5547	811.2197
12	468.3704	900.4983	5.0755	15.2321	350.3668	1102.6780	380.0046	1191.2243
13	629.0509	1530.1593	6.2437	21.4758	425.3059	1528.0439	462.0181	1653.2424
14	769.5291	2299.6839	7.2367	28.7065	490.9828	2019.0267	532.9271	2186.1705
15	906.2091	3205.8890	8.1688	36.8753	552.1488	2571.0215	599.5277	2785.6982
16	1033.4262	4239.3172	8.9707	45.8460	606.5153	3177.5368	658.5453	3444.2435
17	1145.3354	5384.6525	9.6061	55.4521	653.1415	3831.4783	708.9569	4153.1004
18	1239.2498	6624.1024	10.0661	65.5182	691.9461	4523.4244	750.9297	4904.0301
19	1320.8005	7944.9029	10.4364	75.9547	726.1722	5249.5966	788.1150	5692.1451
20	1394.1862	9339.1691	10.7564	86.7111	757.2907	6006.8872	821.9780	6514.1231
21	1463.7598	10802.9289	11.0805	97.7916	788.0921	6792.9793	855.5035	7369.6267
22	1537.0765	12340.0053	11.2911	109.0826	813.0688	7606.0481	882.5571	8252.1838
23	1602.3577	14022.3631	11.5298	120.5704	838.7146	8444.7626	910.3975	9162.5813
24	1675.5006	15700.8637	11.6611	131.9315	847.3485	9292.1111	919.8025	10082.3839
25	1638.3003	17339.1640	10.8744	142.7058	770.0001	10062.1095	833.1395	10949.8734
26	1564.1073	18903.2733	10.4744	153.1802	733.1356	10795.3151	793.8870	11643.7604
27	1507.8057	20431.1390	9.9796	163.1598	692.5590	11447.8741	750.4405	12394.2009
28	1436.2140	21867.3530	9.5305	172.6903	657.4394	12105.3135	712.7625	13106.9634
29	1371.0479	23239.0010	9.1186	181.8089	625.6220	12730.9355	678.4094	13785.3728
30	1309.5595	24548.5606	8.7095	190.5184	595.3401	13326.1756	645.5599	14431.2328
31	1259.1140	25798.7052	8.4141	198.8405	566.4935	13893.1690	615.2152	15046.4480
32	1192.1728	26990.8780	7.9465	206.7870	540.7979	14433.9670	586.6529	15633.1009
33	1139.9062	28127.7842	7.5908	214.3779	516.8606	14950.8275	560.6618	16194.2627
34	1085.5382	29213.3204	7.2695	221.6474	494.8363	15445.6639	537.1159	16731.3787
35	1037.4453	30250.7657	7.0039	228.6513	474.1146	15919.7785	514.7423	17246.1210
36	991.3367	31242.1024	6.7329	235.3843	454.1330	16373.9446	493.1634	17739.3006
37	947.3902	32189.4926	6.4715	241.8557	434.9733	16808.9178	472.5079	18211.8087
38	904.1670	33093.6602	6.2113	248.0670	416.8306	17225.7484	452.3561	18664.1648
39	860.2426	33953.9028	5.9739	254.0409	398.8642	17624.6126	432.9585	19097.1233
40	815.2029	34769.1057	5.6563	259.6972	376.3182	17997.9309	408.5246	19505.6479
41	766.1364	35535.2421	5.3299	265.0271	354.0852	18352.0161	384.4987	19890.1466
42	713.2356	36248.4777	4.9869	269.9749	330.0844	18682.1005	358.3573	20248.5041
43	655.7403	36904.4760	4.5489	274.5238	304.0947	18986.2152	330.1763	20578.6804
44	596.2591	37500.7350	4.1103	278.6341	276.9367	19263.1519	300.7703	20879.4507
45	530.5293	38031.2644	3.6649	282.3037	249.7495	19512.9014	271.0034	21150.4542
46	477.2900	38514.5543	3.2225	285.5262	222.6171	19735.5185	241.5075	21391.9617
47	421.3214	38936.0137	2.8095	288.3356	196.9334	19932.4519	213.8211	21604.8006
48	368.5108	39304.5246	2.4276	290.7633	172.8651	20105.1360	187.6763	21781.5522
49	319.0541	39624.1785	2.0750	292.8383	150.0551	20255.1931	162.8632	21944.4494
50	274.1251	39898.3037	1.7546	294.5929	129.0024	20384.1954	139.9776	22084.4269
51	231.3121	40129.6158	1.4636	296.0565	109.0436	20493.2390	117.5336	22201.9605
52	191.2425	40320.8584	1.1994	297.2559	90.2786	20583.5176	97.2351	22307.5771
53	153.7433	40474.6026	.9537	298.2096	72.5726	20656.1902	78.2040	22385.8011
54	118.0029	40592.6056	.7190	298.9286	55.8379	20712.0281	60.0063	22445.8094
55	85.9395	40678.5451	.5053	299.4339	40.7339	20752.7620	43.8644	22489.6739
56	60.2350	40738.7801	.3237	299.7576	28.6667	20781.4287	30.8438	22520.5176
57	40.1517	40778.9318	.1817	299.9393	19.2199	20800.6485	20.2729	22540.7906
58	26.2538	40805.1857	.1080	300.0465	13.5642	20814.2127	14.1904	22554.9811
59	20.7645	40827.9502	.0670	300.1134	9.9828	20824.1945	10.3711	22565.3524
60	16.0637	40843.9138	.0458	300.1593	7.6952	20831.8897	7.9610	22573.3134
61	12.3016	40856.2156	.0291	300.1884	5.9211	20837.8107	6.0901	22579.4035
62	9.2503	40865.4659	.0173	300.2057	4.2894	20842.1001	4.4900	22583.8935
63	7.9409	40873.4068	.0130	300.2187	3.7574	20845.8575	3.8825	22587.7761
64	6.4235	40880.0763	.0100	300.2287	3.0794	20849.2370	3.1375	22590.9136
65	5.1964	40885.2727	.0080	300.2367	2.4908	20851.7278	2.5372	22593.4507
66	4.0133	40889.2860	.0063	300.2430	1.9234	20853.6512	1.9598	22595.4105
67	2.9467	40892.2347	.0047	300.2477	1.4130	20855.0642	1.4402	22596.8507
68	1.9379	40894.1726	.0031	300.2508	.9266	20855.9927	.9467	22597.7974
69	.9658	40895.1384	.0016	300.2524	.4628	20856.4556	.4719	22597.9194

20856. BCF--MAX GAS PRODUCED IN SCENARIO

TABLE E-2(4)f

SOUTHWEST

ECONOMIC SUMMARY

PROFIT INDICATORS

DISCOUNTED PRESENT WORTH AT 15.0 PCT. (MM$)	1650.19728
DCF RATE OF RETURN (PERCENT)	57.00
PAYOUT TIME (YEARS)	8.38
PROFIT PER INVESTMENT ($/$)	4.138
MAX. UNRECOVERED INVESTMENT (MM$)	152.8877
NET CASH RECOVERY AFTER TAX (MM$)	40895.1384
EXPLORATION EXPENDITURE (MM$)	3145.8331
PRODUCTION INVESTMENT (MM$)	6980.4450
TOTAL INVESTMENT (MM$)	9881.8839
OPERATING EXPENSE (MM$)	3358.5936

TABLE E-2(5)a

Standard Scenario at $5.00 and 15%
Base and Advanced Technologies--Other Southwest

20 YEAR DEVELOPMENT PROGRAM

	LOCATION OF PROSPECTS--			YEAR OF DEVELOPMENT 1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	
1	1601152	NEW MEX#W TEX	15., 5.00	2	2	3	3	3	3	2	0	0	0	0	0	0	0	0	0	0	0	0	0	18
2	1801152	CENTRAL TEX	15., 5.00	2	2	2	3	3	3	3	0	0	0	0	0	0	0	0	0	0	0	0	0	18
3	1601252	NEW MEX#WEST TEX	15., 5.00	0	0	0	1	2	7	18	30	45	45	45	45	45	45	45	45	45	45	45	45	598
4	1801252	CENTRAL TEXAS	15., 5.00	0	0	0	0	0	5	10	15	15	25	25	25	25	25	25	25	25	25	25	10	305
5	2101152	EAST TEX -LA	15.0,5.00	10	10	15	21	20	15	5	0	0	0	0	0	0	0	0	0	0	0	0	0	96
6	2201152	TEXAS GULF SOUTH	15.0,5.00	10	10	9	7	6	5	3	0	0	0	0	0	0	0	0	0	0	0	0	0	50
7	2202152	TEXAS GULF CENTRAL	15.0,5.00	5	5	6	6	5	4	3	0	0	0	0	0	0	0	0	0	0	0	0	0	34
8	2301152	OKLAHOMA	15.0,5.00	0	0	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3
9	2101252	EAST TEX -LA	15.0,5.00	0	0	1	2	5	10	20	30	35	50	75	100	100	100	100	100	100	100	100	100	1128
10	2201252	TEXAS GULF SOUTH	15.0,5.00	0	0	1	3	5	14	27	50	100	150	170	170	170	170	170	170	170	170	170	170	2050
11	2202252	TEXAS GULF CENTRAL	15.0,5.00	0	0	0	4	5	6	7	10	10	10	20	30	40	50	60	60	60	60	60	60	556
12	2301252	OKLAHOMA	15.0,5.00	0	0	0	0	0	4	4	8	8	8	8	8	8	8	8	8	8	8	8	4	108

TABLE E-2(5)b

SUMMARY OF WELL REQUIREMENTS

	CASE	LOCATION OF PROSPECT		NO. PROSP.	WILDCAT WELLS PROD.	WILDCAT WELLS DRY	WILDCAT WELLS TOTAL	W/C SUCCESS RATIO	DEVELOPMENT WELLS PROD.	DEVELOPMENT WELLS DRY	DEVELOPMENT WELLS TOTAL	TOTAL ALL WELLS
1	1601152	NEW MEX#W TEX	15., 5.00	18	10	10	20	.49	445	111	556	576
2	1801152	CENTRAL TEX	15., 5.00	18	6	17	23	.28	261	65	326	349
3	1601252	NEW MEX#WEST TEX	15., 5.00	598	456	235	691	.66	9218	2304	11522	12213
4	1801252	CENTRAL TEXAS	15., 5.00	305	143	270	413	.35	6174	1543	7717	8130
5	2101152	EAST TEX -LA	15.0,5.00	96	32	76	108	.30	364	91	455	563
6	2201152	TEXAS GULF SOUTH	15.0,5.00	50	26	45	71	.37	91	22	113	184
7	2202152	TEXAS GULF CENTRAL	15.0,5.00	34	12	35	47	.27	44	11	55	102
8	2301152	OKLAHOMA	15.0,5.00	3	0	4	4	.11	12	3	15	19
9	2101252	EAST TEX -LA	15.0,5.00	1128	481	805	1286	.37	3160	795	3975	5261
10	2201252	TEXAS GULF SOUTH	15.0,5.00	2050	1172	1783	2955	.40	2423	605	3028	5983
11	2202252	TEXAS GULF CENTRAL	15.0,5.00	556	310	483	793	.39	619	154	773	1566
12	2301252	OKLAHOMA	15.0,5.00	108	54	108	162	.33	1998	499	2497	2659

TABLE E-2(5)c

ANNUAL DRILLING SCHEDULE

	PROSPECT	YEAR	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
1	NEW MEX-W TEX	15., 5.00	64	64	96	96	96	96	64	0	0	0	0	0	0	0	0	0	0	0	0	0
2	CENTRAL TEX	15., 5.00	39	39	39	58	58	58	58	0	0	0	0	0	0	0	0	0	0	0	0	0
3	NEW MEX-WEST TEX	15., 5.00	0	0	0	20	40	143	367	613	919	919	919	919	919	919	919	919	919	919	919	919
4	CENTRAL TEXAS	15., 5.00	0	0	0	0	0	133	266	399	399	666	666	666	666	666	666	666	666	666	666	266
5	EAST TEX -LA	15.0,5.00	58	58	88	123	117	88	29	0	0	0	0	0	0	0	0	0	0	0	0	0
6	TEXAS GULF SOUTH	15.0,5.00	37	37	33	25	22	16	11	0	0	0	0	0	0	0	0	0	0	0	0	0
7	TEXAS GULF CENTRAL	15.0,5.00	15	15	18	18	15	12	9	0	0	0	0	0	0	0	0	0	0	0	0	0
8	OKLAHOMA	15.0,5.00	0	0	6	6	6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	EAST TEX -LA	15.0,5.00	0	0	7	14	37	74	149	224	262	374	561	748	748	748	748	748	748	748	748	748
10	TEXAS GULF SOUTH	15.0,5.00	0	0	2	8	14	40	78	146	292	438	496	496	496	496	496	496	496	496	496	496
11	TEXAS GULF CENTRAL	15.0,5.00	0	0	11	11	14	16	19	28	28	28	56	84	112	140	169	169	169	169	169	169
12	OKLAHOMA	15.0,5.00	0	0	0	0	0	98	98	196	196	196	196	196	196	196	196	196	196	196	196	98
	TOTAL WELLS IN EACH YEAR		213	213	300	379	419	776	1148	1606	2096	2621	2894	3109	3137	3165	3194	3194	3194	3194	3194	2696

TABLE E-2(5)d

INVESTMENT REQUIREMENTS AND RESERVE ADDITIONS

YEAR	INVESTMENT (MM$)	GAS RESERVES ADDED (BCF)	CUMMULATIVE GAS RESERVES
1	186.0	362.6	362.6
2	186.0	362.6	725.2
3	288.4	563.5	1288.7
4	348.8	693.0	1981.7
5	387.2	783.2	2764.9
6	654.4	1294.9	4059.8
7	987.5	1926.2	5985.9
8	1391.2	2837.5	8823.5
9	1695.4	4066.0	12889.5
10	2443.3	5436.5	18326.0
11	2844.8	6405.1	24731.1
12	3143.5	7053.7	31784.8
13	3254.2	7272.1	39057.0
14	3304.8	7490.6	46547.5
15	3475.4	7709.0	54256.5
16	3475.4	7709.0	61965.6
17	3475.4	7709.0	69674.6
18	3475.4	7709.0	77383.6
19	3475.4	7709.0	85092.6
20	3152.6	7172.1	92264.7
	41885.3	TOTAL INVESTMENT	

TABLE E-2(5)e

CASH FLOW AND PRODUCTION SUMMARY

YEAR	ANNUAL CASH FLOW (MM$)	CUMUL. CASH FLOW (MM$)	ANNUAL NGL PRODN (MMB)	CUMUL. NGL PRODN (MMB)	ANNUAL GAS PRODN (BCF)	CUMUL. GAS PRODN (BCF)	ANNUAL GAS PRODN (BCF EQV)	CUMUL. GAS PRODN (BCF EQV)
1	-1.4197	-1.4197	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2	-7.0393	-8.4590	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
3	-38.3966	-46.8556	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
4	-41.7313	-88.5870	.0945	.0945	10.5868	10.5868	11.1348	11.1348
5	-48.5197	-137.1066	.2422	.3367	25.1146	35.7014	26.5195	37.6543
6	-20.2466	-157.3533	.4847	.8214	50.9214	86.6228	53.7324	91.3867
7	19.0660	-138.2873	.6446	1.4660	82.6400	169.2628	87.5348	178.9214
8	55.8406	-82.6464	1.2924	2.9584	119.7108	288.9736	127.2066	306.1280
9	92.5299	9.8835	1.8807	4.8390	174.0192	462.9928	184.9271	491.0552
10	139.0028	148.8863	2.6447	7.5388	257.0155	720.0083	272.6745	763.7332
11	211.5124	360.3987	3.8309	11.3696	385.9370	1105.9454	408.1561	1171.8892
12	430.7472	791.1459	5.4988	16.8684	601.2885	1707.2338	633.1815	1805.0707
13	826.9271	1618.0730	7.7807	24.6491	897.2735	2604.5073	942.4015	2747.4722
14	1390.0553	3008.1283	10.7426	35.3917	1246.8749	3851.3822	1309.1819	4056.6541
15	2031.9878	5039.7161	14.1816	49.5733	1609.7609	5461.1431	1692.0643	5748.7185
16	2746.7016	7786.4176	18.0261	67.5994	1969.6765	7430.8196	2074.2778	7822.9962
17	3449.0042	11235.4218	21.7181	89.3175	2357.2240	9788.0435	2483.1691	10306.1654
18	4179.4995	15414.9213	25.3140	114.6316	2717.7992	12505.8427	2866.6200	13172.7855
19	4879.1392	20294.0606	28.7566	143.3902	3052.6740	15558.5168	3222.4738	16395.1997
20	5547.6127	25841.6733	32.0570	175.4471	3372.5317	18931.0484	3556.5220	19951.7217
21	6205.3612	32047.2345	35.1476	210.6447	3669.1672	22600.2156	3873.3435	23825.0652
22	6691.6124	38738.8469	36.1620	246.8067	3946.1774	26546.3930	4167.5170	27992.5822
23	8029.6151	46968.4620	40.8175	287.6242	4204.1248	30773.5177	4441.4461	32434.0283
24	8127.3762	55095.8382	40.6770	328.3011	4051.1191	34824.6368	4277.0454	36711.0737
25	7968.9780	63064.8162	39.7020	368.0032	3852.3743	38677.0111	4067.7452	40778.8189
26	7646.7805	70711.5968	38.0357	406.1389	3623.1417	42300.1528	3825.7488	44604.5677
27	7243.3717	77954.9685	36.1257	444.2646	3393.3957	45698.5485	3583.9250	48188.4927
28	6864.5635	84819.5320	34.3239	478.5885	3204.5420	48903.0905	3384.3986	51572.8913
29	6526.6425	91346.1665	32.6868	511.3353	3029.4335	51932.6763	3219.0171	54791.9084
30	6203.8894	97550.0560	31.0151	542.3504	2866.8207	54799.5040	3047.7172	57839.1322
31	5893.5887	103443.6447	29.4032	571.7536	2715.9464	57515.4524	2886.4651	60725.5973
32	5596.3104	109039.9551	27.9240	599.6776	2580.9639	60096.4163	2742.9227	63468.5200
33	5321.8393	114361.7944	26.6235	626.3011	2461.6280	62558.0443	2616.0542	66084.5742
34	5068.8064	119430.6008	25.4478	651.7491	2352.5490	64910.5933	2500.3479	68584.9221
35	4834.0355	124264.6363	24.3668	676.1159	2251.0481	67161.6414	2392.6665	70977.5886
36	4613.4752	128878.1116	23.3322	699.4481	2155.1266	69316.7680	2290.6191	73268.2077
37	4407.0376	133285.1491	22.3517	721.8000	2064.7677	71381.5357	2194.1476	75462.3553
38	4207.8677	137493.0168	21.7869	743.5869	1977.0619	73358.5976	2103.4736	77565.8289
39	4012.9953	141506.0121	20.9588	764.5457	1893.9017	75249.1993	2012.1622	79577.9911
40	3825.6352	145331.6473	20.1237	784.6694	1814.1663	77063.3656	1926.8437	81504.8348
41	3636.0615	148967.7088	19.2785	803.9479	1716.3065	78779.6721	1825.1219	83329.9567
42	3442.4504	152410.1622	18.4225	822.3704	1625.0994	80404.7715	1732.5448	85062.5014
43	3238.8872	155649.0494	17.5252	839.8956	1530.7302	81935.5018	1632.3766	86694.8780
44	3026.2010	158675.2504	16.5808	856.4764	1430.6868	83366.1886	1525.6552	88220.5332
45	2814.5119	161489.7623	15.5845	872.0609	1330.9620	84697.1506	1419.5141	89640.0473
46	2590.2433	164080.0056	14.5055	886.5664	1225.1667	85922.3173	1306.3417	90946.3890
47	2359.0176	166439.0233	13.3404	899.9068	1116.1050	87038.4223	1190.0742	92136.4632
48	2117.4486	168556.4719	12.0714	911.9782	1002.2826	88040.7049	1068.8057	93205.2689
49	1871.3290	170427.8009	10.7144	922.6926	886.4153	88927.1202	945.5483	94150.8172
50	1625.3175	172053.1184	9.3330	932.0256	770.4783	89697.5985	821.6106	94972.4278
51	1378.5486	173431.6670	7.9376	939.9632	653.9952	90351.5937	697.4830	95669.9108
52	1128.7755	174560.4426	6.5668	946.5300	540.8313	90892.4250	576.7560	96246.6669
53	910.6320	175471.0746	5.2456	951.7756	432.5984	91325.0234	461.3231	96707.9900
54	698.2731	176169.3476	3.9615	955.7371	331.9419	91656.9653	354.0445	97061.9345
55	512.3204	176681.6680	2.8267	958.5638	244.0199	91900.9852	260.2413	97322.1758
56	358.3541	177040.0221	1.8370	960.4008	171.3607	92072.3459	182.7514	97504.9272
57	235.8908	177285.9128	1.0775	961.4783	113.4740	92185.8199	119.7232	97624.6504
58	156.3572	177442.2700	.6335	962.1118	76.7634	92262.5833	80.4378	97705.0882
59	113.4945	177555.7645	.3814	962.4932	54.7250	92317.3083	56.8054	97761.8936
60	62.8051	177641.5726	.2461	963.4222	39.9503	92346.6411	41.3779	97803.8651
61	61.0151	177702.5877	.1419	963.5641	29.3993	92377.4404	30.2223	97833.1123
62	47.5308	177750.1244	.0866	963.6507	22.3240	92400.2644	23.1264	97856.4386
63	36.9343	177787.0587	.0653	963.7159	15.6681	92416.6325	16.0065	97872.8450
64	31.8252	177820.8839	.0511	963.7670	15.2605	92434.1930	15.5508	97888.4417
65	25.3058	177846.1897	.0401	963.8071	12.1310	92446.3239	12.3836	97900.8254
66	19.0791	177865.2688	.0315	963.8387	9.1431	92455.4670	9.3260	97910.1514
67	13.8083	177879.0771	.0237	963.8623	6.5142	92462.0812	6.6514	97916.8028
68	9.0274	177888.1045	.0158	963.8781	4.3232	92466.4044	4.4147	97921.2175
69	4.5011	177892.6056	.0079	963.8860	2.1558	92468.5602	2.2015	97923.4190

92469. BCF--MAX GAS PRODUCED IN [illegible]

TABLE E-2(5)f

ECONOMIC SUMMARY

PROFIT INDICATORS

DISCOUNTED PRESENT WORTH AT 15.0 PCT. (MM$)	5347.47467
DCF RATE OF RETURN (PERCENT)	55.20
PAYOUT TIME (YEARS)	7.89
PROFIT PER INVESTMENT ($/$)	4.247
MAX. UNRECOVERED INVESTMENT (MM$)	157.3533
NET CASH RECOVERY AFTER TAX (MM$)	177892.6056
EXPLORATION EXPENDITURE (MM$)	12641.0706
PRODUCTION INVESTMENT (MM$)	30220.5987
TOTAL INVESTMENT (MM$)	41885.2667
OPERATING EXPENSE (MM$)	14843.3696

TABLE E-2(6)a

Standard Scenario at $5.00 and 15%
Base and Advanced Technologies--Eastern U.S.

20 YEAR DEVELOPMENT PROGRAM

	YEAR OF DEVELOPMENT / LOCATION OF PROSPECTS--		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	
1	1202152	ERN CNTRL SHALLOW 15., 5.00	1	1	2	4	5	5	5	5	5	5	0	0	0	0	0	0	0	0	0	0	38
2	1217152	ERN CNTRL SHALLOW B15., 5.00	1	2	3	4	8	8	8	9	9	9	0	0	0	0	0	0	0	0	0	0	62
3	1218152	ERN CNTRL SHALLOW C15., 5.00	1	1	2	5	5	5	5	5	5	5	0	0	0	0	0	0	0	0	0	0	39
4	1220152	ERN CNTRL SHALLOW D15., 5.00	4	4	8	20	20	21	21	21	21	21	0	0	0	0	0	0	0	0	0	0	161
5	1301152	EASTERN COASTAL 15., 5.00	10	15	20	30	40	43	43	43	43	44	0	0	0	0	0	0	0	0	0	0	331
6	1302152	EASTERN COASTAL 15., 5.00	5	10	15	20	25	27	29	29	29	30	0	0	0	0	0	0	0	0	0	0	219
7	1303152	EASTERN COASTAL 15., 5.00	3	6	9	12	12	12	12	12	12	12	0	0	0	0	0	0	0	0	0	0	102
8	1307152	EASTERN COASTAL 15., 5.00	13	15	20	30	40	50	50	50	55	55	0	0	0	0	0	0	0	0	0	0	378
9	1601152	ERN CNTRL INTERMED 15., 5.00	3	5	7	12	13	14	14	14	14	14	0	0	0	0	0	0	0	0	0	0	110
10	1202252	ERN CNTRL SHALLOW A15., 5.00	0	0	0	0	2	3	4	4	5	10	15	20	20	20	20	20	20	21	21	21	226
11	1217252	ERN CNTRL SHALLOW B15., 5.00	0	0	0	0	2	4	6	8	9	15	25	30	35	35	35	35	35	35	35	35	379
12	1218252	ERN CNTRL SHALLOW C15., 5.00	0	0	0	0	2	3	3	4	5	10	15	16	16	16	16	16	16	16	16	16	166
13	1220252	ERN CNTRL SHALLOW D15., 5.00	0	0	0	0	2	3	4	5	5	7	10	10	11	11	11	11	11	11	11	11	134
14	1301252	EASTERN COASTAL 15., 5.00	0	0	0	0	0	2	4	10	10	13	15	15	15	15	15	15	15	15	15	15	159
15	1302252	EASTERN COASTAL 15., 5.00	0	0	0	0	0	1	3	5	5	5	6	7	7	7	7	7	7	7	8	9	91
16	1303252	EASTERN COASTAL 15., 5.00	0	0	0	0	0	1	1	2	3	3	3	3	3	3	3	3	3	3	3	3	40
17	1307252	EASTERN COASTAL 15., 5.00	0	0	0	0	0	1	5	10	15	18	18	18	18	18	18	18	18	18	18	18	229
18	1601252	ERN CNTRL INTERMED 15., 5.00	0	0	0	1	4	7	10	10	10	10	10	10	10	10	10	10	10	10	10	10	152
19	2101152	ERN CNTRL DEEP 15., 5.00	1	1	2	5	5	5	5	5	5	5	0	0	0	0	0	0	0	0	0	0	39
20	2101252	ERN CNTRL DEEP 15., 5.00	0	0	0	0	2	3	4	4	5	10	15	20	20	20	20	20	23	25	25	25	241

TABLE E-2(6)b

SUMMARY OF WELL REQUIREMENTS

	CASE	LOCATION OF PROSPECT	NO. PROSP.	WILDCAT WELLS PROD.	WILDCAT WELLS DRY	WILDCAT WELLS TOTAL	W/C SUCCESS RATIO	DEVELOPMENT WELLS PROD.	DEVELOPMENT WELLS DRY	DEVELOPMENT WELLS TOTAL	TOTAL ALL WELLS
1	1202152	ERN CNTRL SHALLOW 15., 5.00	38	12	60	72	.17	280	70	350	422
2	1217152	ERN CNTRL SHALLOW B15., 5.00	62	11	108	119	.10	124	31	155	274
3	1218152	ERN CNTRL SHALLOW C15., 5.00	39	15	58	73	.21	337	84	421	494
4	1220152	ERN CNTRL SHALLOW D15., 5.00	161	64	240	304	.21	748	187	935	1239
5	1301152	EASTERN COASTAL 15., 5.00	331	157	173	330	.48	901	225	1126	1456
6	1302152	EASTERN COASTAL 15., 5.00	219	103	115	218	.47	1709	427	2136	2354
7	1303152	EASTERN COASTAL 15., 5.00	102	47	54	101	.47	798	199	997	1098
8	1307152	EASTERN COASTAL 15., 5.00	378	116	261	377	.31	2250	562	2812	3189
9	1601152	ERN CNTRL INTERMED 15., 5.00	110	62	65	127	.49	2722	680	3402	3529
10	1202252	ERN CNTRL SHALLOW A15., 5.00	226	75	359	434	.17	815	203	1018	1452
11	1217252	ERN CNTRL SHALLOW B15., 5.00	379	73	665	738	.10	383	95	478	1216
12	1218252	ERN CNTRL SHALLOW C15., 5.00	186	74	278	352	.21	1092	273	1365	1717
13	1220252	ERN CNTRL SHALLOW D15., 5.00	134	53	200	253	.21	462	115	577	830
14	1301252	EASTERN COASTAL 15., 5.00	169	96	92	188	.51	248	62	310	498
15	1302252	EASTERN COASTAL 15., 5.00	91	42	48	90	.47	1016	254	1270	1360
16	1303252	EASTERN COASTAL 15., 5.00	40	18	21	39	.47	478	119	597	636
17	1307252	EASTERN COASTAL 15., 5.00	229	70	158	228	.31	964	241	1205	1433
18	1601252	ERN CNTRL INTERMED 15., 5.00	152	116	59	175	.66	2343	585	2928	3103
19	2101152	ERN CNTRL DEEP 15., 5.00	39	13	31	44	.30	161	40	201	245
20	2101252	ERN CNTRL DEEP 15., 5.00	241	102	172	274	.37	679	169	848	1122

TABLE E-2(6)c

ANNUAL DRILLING SCHEDULE

	PROSPECT		YEAR	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
1	ERN CNTRL SHALLOW	15.,	5.00	11	11	22	44	55	55	55	55	55	55	0	0	0	0	0	0	0	0	0	0
2	ERN CNTRL SHALLOW	B15.,	5.00	4	4	13	17	35	35	40	40	40	40	0	0	0	0	0	0	0	0	0	0
3	ERN CNTRL SHALLOW	C15.,	5.00	12	12	25	63	63	63	63	63	63	63	0	0	0	0	0	0	0	0	0	0
4	ERN CNTRL SHALLOW	D15.,	5.00	30	30	61	154	154	161	161	161	161	161	0	0	0	0	0	0	0	0	0	0
5	ASTERN COASTAL	15.,	5.00	44	66	88	132	176	189	189	189	189	193	0	0	0	0	0	0	0	0	0	0
6	EASTERN COASTAL	15.,	5.00	53	107	161	215	269	290	312	312	312	312	0	0	0	0	0	0	0	0	0	0
7	EASTERN COASTAL	15.,	5.00	32	64	97	129	129	129	129	129	129	129	0	0	0	0	0	0	0	0	0	0
8	EASTERN COASTAL	15.,	5.00	104	120	161	241	322	402	402	402	443	443	0	0	0	0	0	0	0	0	0	0
9	ERN CNTRL INTERMED	15.,	5.00	96	160	224	385	417	449	449	449	449	449	0	0	0	0	0	0	0	0	0	0
10	ERN CNTRL SHALLOW	A15.,	5.00	0	0	0	6	12	19	25	25	32	64	96	128	128	128	128	128	128	135	135	135
11	ERN CNTRL SHALLOW	B15.,	5.00	0	0	0	0	6	12	19	25	25	48	80	96	112	112	112	112	112	112	112	112
12	ERN CNTRL SHALLOW	C15.,	5.00	0	0	0	0	18	27	27	36	46	92	138	147	147	147	147	147	147	147	147	147
13	ERN CNTRL SHALLOW	D15.,	5.00	0	0	0	0	12	18	24	31	31	43	62	62	62	68	68	68	68	68	68	68
14	EASTERN COASTAL	15.,	5.00	0	0	0	0	0	5	10	20	25	34	39	39	39	39	39	39	39	39	39	39
15	EASTERN COASTAL	15.,	5.00	0	0	0	0	0	14	44	74	74	74	89	104	104	104	104	104	104	104	119	134
16	EASTERN COASTAL	15.,	5.00	0	0	0	0	0	15	15	31	47	47	47	47	47	47	47	47	47	47	47	47
17	EASTERN COASTAL	15.,	5.00	0	0	0	0	0	6	31	62	93	112	112	112	112	112	112	112	112	112	112	112
18	ERN CNTRL INTERMED	15.,	5.00	0	0	0	20	61	143	204	204	204	204	204	204	204	204	204	204	204	204	204	204
19	ERN CNTRL DEEP	15.,	5.00	5	5	11	29	29	29	29	29	29	29	0	0	0	0	0	0	0	0	0	0
20	EPN CNTRL DEEP	15.,	5.00	0	0	0	0	14	22	29	29	37	74	112	149	149	149	149	149	172	187	187	187
	TOTAL WELLS IN EACH YEAR			391	583	863	1429	1792	2083	2257	2372	2488	2676	979	1088	1110	1110	1110	1110	1133	1155	1170	1185

TABLE E-2(6)d

INVESTMENT REQUIREMENTS AND RESERVE ADDITIONS

YEAR	INVESTMENT (MM$)	GAS RESERVES ADDED (BCF)	CUMULATIVE GAS RESERVES
1	214.7	312.2	312.2
2	325.6	479.9	792.1
3	472.6	712.9	1505.0
4	746.6	1162.1	2667.1
5	952.8	1498.5	4165.7
6	1146.1	1775.2	5940.9
7	1261.9	1962.4	7903.3
8	1355.2	2104.2	10007.6
9	1448.7	2217.9	12225.4
10	1565.4	2469.7	14695.1
11	681.6	1251.1	15946.2
12	753.3	1414.7	17360.9
13	763.2	1444.6	18805.5
14	763.2	1444.6	20250.0
15	763.2	1444.6	21694.6
16	763.2	1444.6	23139.1
17	785.7	1496.2	24635.3
18	803.4	1537.6	26172.9
19	813.6	1550.4	27723.3
20	823.8	1563.3	29286.6
	17203.6	TOTAL INVESTMENT	

TABLE E-2(6)e

CASH FLOW AND PRODUCTION SUMMARY

YEAR	ANNUAL CASH FLOW (MM$)	CUMUL. CASH FLOW (MM$)	ANNUAL NGL PRODN (MMB)	CUMUL. NGL PRODN (MMB)	ANNUAL GAS PRODN (BCF)	CUMUL. GAS PRODN (BCF EQ)	ANNUAL GAS PRODN (BCF EQ)	CUMUL. GAS PRODN (BCF EQ)
1	-.8375	-.8375	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2	-8.7972	-9.6348	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
3	-27.1485	-36.7832	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
4	-39.6651	-76.4483	.0605	.0605	4.9853	4.9853	5.3362	5.3362
5	-74.2744	-150.7228	.2816	.3421	22.0646	27.0499	23.6560	29.0341
6	-71.2759	-221.9987	.7012	1.0433	54.4458	81.5157	58.5325	87.5669
7	-53.7768	-275.7775	1.2041	2.3274	100.7695	182.2852	108.2174	195.7843
8	-9.6465	-285.4240	2.0747	4.4021	155.8523	348.2375	177.6857	373.7700
9	74.8152	-210.6088	3.0548	7.4569	250.9060	599.1435	268.8437	642.2137
10	197.7535	-12.8553	4.1788	11.6357	350.2644	949.3081	374.8016	1016.9153
11	360.9974	348.1421	5.3085	17.0042	456.7338	1406.0419	487.8742	1504.5885
12	566.1116	908.2537	6.5909	23.5951	564.8609	1970.9028	602.8682	2107.4566
13	802.7846	1711.0383	7.9242	31.5193	678.1391	2648.8419	724.0004	2831.5570
14	996.2264	2709.2647	9.0791	40.5984	774.1778	3423.0197	826.6265	3658.1835
15	1278.8471	3988.1118	9.7137	50.3121	832.7028	4255.7225	888.0423	4547.2329
16	1375.1293	5363.2431	9.8218	60.1340	854.3655	5110.1081	911.5521	5458.7850
17	1450.2623	6813.5054	9.9565	70.0904	875.7352	5985.8433	934.4927	6393.2777
18	1511.0629	8324.5683	10.1514	80.2418	907.4754	6893.3187	966.2933	7359.5710
19	1576.2259	9900.7942	10.4167	90.6604	939.8146	7833.1333	1000.2429	8359.8138
20	1646.6961	11547.4903	10.7657	101.4262	974.5826	8807.7159	1037.1249	9396.9387
21	1727.2170	13274.6974	11.1591	112.5853	1013.3492	9821.0651	1075.0715	10471.9102
22	1830.9770	15105.6743	11.5583	124.1436	1054.7186	10884.7836	1112.7594	11584.6696
23	1974.9641	17080.6384	11.9644	136.1080	1096.1139	11947.8974	1150.4864	12735.1560
24	2013.5641	19094.2025	11.8044	147.9137	1093.2562	13039.1536	1149.7537	13884.9097
25	2063.0569	21157.2805	11.3498	159.2636	1053.6959	14092.8525	1119.5191	15004.4288
26	2007.5737	23164.8632	10.6979	169.9604	1000.3994	15093.2520	1062.9370	16067.3658
27	1920.9432	25085.8064	10.0633	180.0237	947.4584	16040.7104	1006.5566	17073.9224
28	1826.3544	26912.1608	9.4613	189.5050	899.5309	16940.2413	954.7224	18028.6448
29	1741.3705	28653.5313	8.9494	198.4544	857.2201	17797.4614	909.8295	18938.4743
30	1663.7104	30317.2417	8.4474	206.9018	818.3513	18615.8127	868.6141	19807.0884
31	1590.2290	31907.4707	7.9705	214.8723	781.9164	19397.7291	828.9453	20635.9337
32	1518.9698	33426.4406	7.5287	222.4010	748.1831	20145.9122	793.9474	21429.8811
33	1451.3080	34877.7486	7.1315	229.5325	717.4125	20863.3246	761.7749	22191.6561
34	1386.0432	36263.7918	6.7814	236.3139	688.3138	21543.1384	730.9458	22913.7018
35	1329.4508	37593.2427	6.4705	242.7844	663.2765	22206.4149	704.5023	23618.2041
36	1273.3464	38866.5941	6.1655	248.9499	639.1058	22844.5222	678.8617	24297.0658
37	1218.6911	40087.2852	5.9194	254.8693	613.2431	23457.7652	651.4779	24948.5437
38	1162.8597	41250.1449	5.6655	260.5348	587.5000	24045.2651	624.0313	25572.5750
39	1104.2077	42354.3526	5.4199	265.9546	563.3587	24608.6238	598.3777	26170.9527
40	1044.3525	43398.7051	5.1788	271.1335	531.6847	25137.4085	564.7219	26735.0746
41	962.5228	44361.2279	4.9389	276.0723	501.7909	25639.2093	530.4364	27265.5110
42	918.4375	45299.6654	4.7019	280.7742	470.5543	26109.7636	497.8393	27763.3502
43	853.3316	46152.9970	4.4689	285.2431	435.6151	26545.3787	464.5345	28227.8847
44	788.0767	46941.0738	4.2408	289.5039	406.4280	26954.7977	431.0245	28658.9092
45	725.5069	47666.5807	4.0205	293.5243	375.4242	27330.2220	398.1429	29057.0521
46	667.0035	48333.5842	3.8039	297.3282	346.4040	27676.6259	368.4863	29425.5384
47	609.7667	48943.3509	3.5856	300.9138	318.0875	27994.7134	338.8742	29764.4126
48	553.3156	49496.6666	3.3632	304.2770	290.1597	28284.8732	309.6602	30074.0728
49	498.8370	49995.5036	3.1368	307.4138	263.2162	28548.0893	281.4096	30355.4824
50	446.1139	50441.6175	2.9116	310.3254	237.1768	28785.2662	254.0840	30609.5665
51	391.6019	50833.2193	2.6933	312.9187	209.8341	28995.1003	225.2810	30834.8474
52	337.9966	51171.1256	2.4001	315.3188	182.7138	29177.8141	196.6346	31031.4820
53	284.4584	51455.5843	2.1173	317.5061	155.5172	29333.3312	167.7977	31174.8667
54	230.4459	51686.0302	1.8070	319.3132	127.6694	29461.1506	138.1502	31313.0169
55	179.6226	51865.6528	1.4936	320.8067	101.1843	29562.3349	109.5475	31422.5644
56	135.4978	52001.1506	1.1947	322.0014	77.8034	29640.1383	84.7326	31507.2970
57	100.2080	52101.3586	.9284	322.9299	58.7351	29698.8733	64.1200	31571.4170
58	73.1187	52174.4774	.7156	323.6455	43.4581	29742.3315	47.5085	31618.9255
59	51.5192	52225.9965	.5313	324.1767	30.7687	29772.9502	33.6100	31652.5355
60	32.2721	52258.2687	.3590	324.5357	19.1002	29792.1504	21.2714	31673.8069
61	27.9426	52286.2113	.3156	324.8513	16.7378	29808.8882	18.5661	31692.3730
62	23.7334	52309.9446	.2711	325.1224	14.3300	29823.2071	15.9025	31708.2755
63	19.7859	52329.7305	.2266	325.3510	12.0471	29835.2542	13.3731	31722.2506
64	16.1516	52345.8821	.1884	325.5394	9.9181	29845.1723	11.0108	31733.3008
65	12.6923	52358.7744	.1517	325.6912	7.9765	29853.1508	8.8585	31742.1593
66	10.0662	52368.8406	.1191	325.8103	6.2575	29859.4083	6.9494	31749.1087
67	7.3900	52376.2305	.0978	325.8980	4.6092	29864.0176	5.1183	31754.2269
68	4.8493	52381.0798	.0577	325.9558	3.0352	29867.0528	3.3711	31757.5980
69	2.4336	52383.5134	.0287	325.9845	1.5140	29868.5668	1.6807	31759.2789

29869. BCF--MAX GAS PRODUCED IN SCENARIO

TABLE E-2(6)f

ECONOMIC SUMMARY

PROFIT INDICATORS

DISCOUNTED PRESENT WORTH AT 15.0 PCT. (MM$)	1989.04653
DCF RATE OF RETURN (PERCENT)	46.00
PAYOUT TIME (YEARS)	9.04
PROFIT PER INVESTMENT ($/$)	3.045
MAX. UNRECOVERED INVESTMENT (MM$)	285.4240
NET CASH RECOVERY AFTER TAX (MM$)	52383.5334
EXPLORATION EXPENDITURE (MM$)	3277.4364
PRODUCTION INVESTMENT (MM$)	14147.4110
TOTAL INVESTMENT (MM$)	17203.6484
OPERATING EXPENSE (MM$)	11176.1086

TABLE E-2(7)a

Standard Scenario at $5.00 and 15%
Base and Advanced Technologies--Mid-Continent U.S.

20 YEAR DEVELOPMENT PROGRAM

	YEAR OF DEVELOPMENT		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	
	LOCATION OF PROSPECTS--																						
1	1202152	MIDCON SHALLOW FMN A15., 5.00	0	0	1	3	3	3	4	4	4	2	0	0	0	0	0	0	0	0	0	0	24
2	1217152	MIDCON SHALLOW FMN B15., 5.00	1	1	2	2	4	5	5	6	6	8	0	0	0	0	0	0	0	0	0	0	40
3	1218152	MIDCON SHALLOW FMN C15., 5.00	0	0	1	3	3	4	4	4	4	2	0	0	0	0	0	0	0	0	0	0	24
4	1220152	MIDCON SHALLOW FMN D15., 5.00	0	2	2	2	2	4	4	4	3	3	0	0	0	0	0	0	0	0	0	0	25
5	1501152	MIDCON DEEP 15., 5.00	1	2	3	3	3	3	3	3	3	2	0	0	0	0	0	0	0	0	0	0	26
6	1801152	MIDCON INTERMEDIATE 15., 5.00	1	1	2	2	2	2	2	2	3	3	0	0	0	0	0	0	0	0	0	0	20
7	1202252	MIDCON SHALLOW FMN A15., 5.00	0	0	0	0	0	0	0	0	1	3	4	4	4	4	4	4	4	4	4	4	44
8	1217252	MIDCON SHALLOW FMN B15., 5.00	0	0	0	0	0	0	0	0	1	2	3	5	7	8	8	8	8	8	9	10	77
9	1218252	MIDCON SHALLOW FMN C15., 5.00	0	0	0	0	0	0	0	0	0	0	4	4	4	4	4	4	4	4	4	4	40
10	1220252	MIDCON SHALLOW FMN D15., 5.00	0	0	0	0	0	0	0	0	0	0	4	4	4	4	4	4	4	4	4	4	40
11	1501252	MIDCON DEEP 15., 5.00	0	0	0	0	0	0	0	0	2	2	2	3	3	3	3	3	3	3	3	2	32
12	1801252	MIDCON INTERMEDIATE 15., 5.00	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	0	11

TABLE E-2(7)b

SUMMARY OF WELL REQUIREMENTS

	CASE	LOCATION OF PROSPECT	NO. PROSP.	WILDCAT WELLS PROD.	WILDCAT WELLS DRY	WILDCAT WELLS TOTAL	W/C SUCCESS RATIO	DEVELOPMENT WELLS PROD.	DEVELOPMENT WELLS DRY	DEVELOPMENT WELLS TOTAL	TOTAL ALL WELLS
1	1202152	MIDCON SHALLOW FMN A15., 5.00	24	8	38	46	.17	177	44	221	267
2	1217152	MIDCON SHALLOW FMN B15., 5.00	40	7	70	77	.10	80	20	100	177
3	1218152	MIDCON SHALLOW FMN C15., 5.00	24	9	35	44	.21	207	51	258	302
4	1220152	MIDCON SHALLOW FMN D15., 5.00	26	10	38	48	.21	120	30	150	198
5	1501152	MIDCON DEEP 15., 5.00	26	14	15	29	.49	643	160	803	832
6	1801152	MIDCON INTERMEDIATE 15., 5.00	20	7	19	26	.28	290	72	362	388
7	1202252	MIDCON SHALLOW FMN A15., 5.00	44	14	70	84	.17	158	39	197	281
8	1217252	MIDCON SHALLOW FMN B15., 5.00	77	14	135	149	.10	77	19	95	245
9	1218252	MIDCON SHALLOW FMN C15., 5.00	40	16	59	75	.21	234	58	292	367
10	1220252	MIDCON SHALLOW FMN D15., 5.00	40	16	59	75	.21	138	34	172	247
11	1501252	MIDCON DEEP 15., 5.00	32	24	12	36	.66	493	123	616	652
12	1801252	MIDCON INTERMEDIATE 15., 5.00	11	5	9	14	.35	222	55	277	291

TABLE E-2(7)c

ANNUAL DRILLING SCHEDULE

	PROSPECT	YEAR	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
1	MIDCON SHALLOW FMN A15.,	5.00	0	0	11	33	33	33	44	44	44	22	0	0	0	0	0	0	0	0	0	0
2	MIDCON SHALLOW FMN B15.,	5.00	4	4	8	8	17	22	22	26	26	35	0	0	0	0	0	0	0	0	0	0
3	MIDCON SHALLOW FMN C15.,	5.00	0	0	12	38	38	38	50	50	50	25	0	0	0	0	0	0	0	0	0	0
4	MIDCON SHALLOW FMN D15.,	5.00	0	15	15	15	15	30	30	30	23	23	0	0	0	0	0	0	0	0	0	0
5	MIDCON DEEP 15.,	5.00	32	64	96	96	96	96	96	96	96	64	0	0	0	0	0	0	0	0	0	0
6	MIDCON INTERMEDIATE 15.,	5.00	19	19	39	39	39	39	39	39	58	58	0	0	0	0	0	0	0	0	0	0
7	MIDCON SHALLOW FMN A15.,	5.00	0	0	0	0	0	0	0	0	6	19	25	25	25	25	25	25	25	25	25	25
8	MIDCON SHALLOW FMN B15.,	5.00	0	0	0	0	0	0	0	0	3	6	9	16	22	25	25	25	25	25	28	32
9	MIDCON SHALLOW FMN C15.,	5.00	0	0	0	0	0	0	0	0	0	0	36	36	36	36	36	36	36	36	36	36
10	MIDCON SHALLOW FMN D15.,	5.00	0	0	0	0	0	0	0	0	0	0	24	24	24	24	24	24	24	24	24	24
11	MIDCON DEEP 15.,	5.00	0	0	0	0	0	0	0	0	40	40	40	61	61	61	61	61	61	61	61	40
12	MIDCON INTERMEDIATE 15.,	5.00	0	0	0	0	0	0	0	0	26	26	26	26	26	26	26	26	26	26	26	0
	TOTAL WELLS IN EACH YEAR		55	102	181	229	238	258	281	285	372	318	160	188	194	197	197	197	197	197	200	157

TABLE E-2(7)d

INVESTMENT REQUIREMENTS AND RESERVE ADDITIONS

YEAR	INVESTMENT (MM$)	GAS RESERVES ADDED (BCF)	CUMMULATIVE GAS RESERVES
1	21.0	30.9	30.9
2	37.8	60.1	91.1
3	64.9	104.7	195.7
4	77.2	131.8	327.6
5	79.8	140.2	467.8
6	85.4	157.5	625.3
7	91.5	171.1	796.3
8	92.8	175.3	971.6
9	147.6	266.1	1237.7
10	131.9	249.5	1487.2
11	90.6	183.1	1670.3
12	107.2	214.3	1884.6
13	109.9	222.9	2107.5
14	111.2	227.2	2334.7
15	111.2	227.2	2561.9
16	111.2	227.2	2789.1
17	111.2	227.2	3016.3
18	111.2	227.2	3243.5
19	112.5	231.5	3475.1
20	82.1	182.9	3657.9
	1888.2 TOTAL INVESTMENT		

TABLE E-2(7)e

CASH FLOW AND PRODUCTION SUMMARY

YEAR	ANNUAL CASH FLOW (MM$)	CUMUL. CASH FLOW (MM$)	ANNUAL NGL PRODN (MMB)	CUMUL. NGL PRODN (MMB)	ANNUAL GAS PRODN (BCF)	CUMUL. GAS PRODN (BCF)	ANNUAL GAS PRODN (BCF EQ1)	CUMUL. GAS PRODN (BCF EQ1)
1	-.0664	-.0664	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2	-.9749	-1.0413	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
3	-2.2253	-3.2665	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
4	-6.5462	-10.4947	.0016	.0016	.3603	.3603	.3654	.3654
5	-10.9739	-21.3776	.0064	.0080	1.5411	[illegible]	1.5765	1.9479
6	-14.3761	-35.7517	.0131	.0211	3.6729	[illegible]	3.7603	[illegible]
7	-12.6298	-48.3815	.0375	.0587	8.0537	13.6278	8.2714	14.1747
8	-9.7264	-58.1079	.0578	.1164	13.1669	26.7976	13.5048	27.6845
9	-1.2092	-59.7135	.0804	.2068	19.3738	46.8714	20.3865	48.0710
10	8.1247	-51.5889	.1154	.3222	26.8561	73.7295	27.5273	75.5982
11	17.2776	-33.6113	.1407	.4629	34.1629	107.8924	34.9811	110.5793
12	28.4935	-5.2178	.1704	.6333	42.7855	150.6804	43.7760	154.3571
13	42.5168	37.1770	.2037	.8367	52.1203	202.8007	53.3963	207.7533
14	63.2217	100.3988	.2301	1.0667	60.5855	263.3862	61.9163	[illegible]
15	88.1404	188.5392	.3016	1.3683	71.3251	334.7113	73.0743	[illegible]
16	104.6278	293.1669	.3007	1.6690	81.3197	416.0310	83.4329	[illegible]
17	121.9305	415.0949	.3036	2.0126	89.3264	505.3774	91.5500	517.5305
18	138.5541	553.6990	.4121	2.5246	97.7795	603.1570	100.1698	617.7959
19	154.3175	707.4165	.4416	2.9662	106.1346	709.2915	108.6958	726.4937
20	170.3061	877.4225	.4702	3.4364	114.1314	823.4230	116.8586	843.3441
21	186.9330	1064.3556	.4928	3.9292	121.6071	945.0300	124.5262	[illegible]
22	206.3235	1270.6791	.5189	4.4511	126.8625	1073.8925	131.8921	1099.7707
23	231.2528	1502.1338	.5354	4.9865	135.4234	1209.3159	138.5464	1238.3252
24	244.0307	1746.7414	.5495	5.5360	138.7000	1348.0059	141.8871	[illegible]
25	258.3301	2005.0779	.5544	6.0904	138.7002	1486.7062	141.9236	[illegible]
26	265.7558	2271.8337	.5814	6.6192	132.9816	1619.7756	136.0081	[illegible]
27	267.0648	2538.9236	.5961	7.1153	126.9920	1746.7677	129.8669	1782.5249
28	237.9127	2776.8363	.4759	7.5892	121.5486	1868.3163	124.3088	1912.8337
29	222.1648	2999.0011	.4525	8.0417	116.7114	1985.0277	119.3574	2031.1911
30	220.1624	3219.1635	.4333	8.4750	112.2272	2097.2549	114.7766	2145.9677
31	212.1327	3431.2962	.4131	8.8881	108.0515	2205.3064	110.5465	2256.5141
32	204.4354	3635.7316	.3927	9.2808	104.2358	2309.5422	106.6310	2363.1451
33	197.4476	3833.1792	.3800	9.6607	100.6078	2410.1500	103.0171	2466.1623
34	190.8181	4023.9972	.3670	10.0346	97.2656	[illegible]	99.5140	2565.6763
35	184.1174	4208.1146	.3536	10.3904	94.7252	2602.7608	96.9578	2663.0250
36	177.5757	4364.6898	.3437	10.7341	91.7361	2694.4970	93.7297	2756.7547
37	171.1401	4535.8300	.3310	11.0659	88.6414	2783.1384	90.5661	2847.3208
38	164.8163	4700.1463	.3200	11.3859	85.7576	[illegible]	87.7138	[illegible]
39	157.1271	4857.2734	.3081	11.6942	81.0220	2950.3183	83.0004	[illegible]
40	149.3160	5006.7895	.2966	11.9908	77.9994	3028.3177	79.7196	3097.5642
41	141.7591	5148.5486	.2852	12.2760	74.0703	3102.3880	75.7247	3173.2889
42	133.7516	5282.3031	.2744	12.5504	69.0986	3172.4866	71.5900	3244.8789
43	125.9836	5407.6926	.2635	12.8139	65.7194	3238.1660	67.2478	[illegible]
44	118.0827	5525.7754	.2522	13.0661	61.2498	[illegible]	62.7068	[illegible]
45	108.1920	5632.9273	.2414	13.3075	56.9369	3356.1907	58.2388	3433.3742
46	[illegible]	5732.0642	.2298	13.5373	52.3494	3408.5401	53.7320	3487.1062
47	88.4978	5820.5621	.2163	13.7536	47.6070	[illegible]	48.9232	[illegible]
48	80.8675	5901.4295	.2008	13.9543	42.7799	3499.0870	43.9444	3579.9734
49	73.4884	5974.9179	.1892	14.1434	38.5527	3537.6397	39.6265	[illegible]
50	67.3513	6042.2692	.1692	14.3040	32.8466	3570.4863	33.6302	3652.7328
51	51.9735	6094.2427	.1494	14.4500	27.6522	3597.1385	28.5161	3681.2487
52	42.1467	6136.3894	.1283	14.5803	22.5660	3619.7045	23.3103	3704.5590
53	32.5072	6168.8966	.1060	14.6923	17.6556	3637.3601	18.2705	3722.8296
54	24.3519	6193.2485	.0855	14.7779	13.1894	3650.5494	13.6054	3736.5150
55	17.1706	6210.4191	.0673	14.8452	9.3557	3660.1592	9.7460	3746.2610
56	11.8178	6222.2369	.0500	14.8952	6.2107	3666.3700	6.5107	3752.7717
57	7.4274	6229.6643	.0365	14.9317	3.9503	3670.3201	4.1018	3756.8735
58	4.1814	6233.8457	.0246	14.9571	2.7983	3673.1183	2.9410	3759.8146
59	2.1030	6235.9486	.0133	14.9709	1.1560	3674.2744	1.2369	3761.0515
60	.5709	6236.5195	.0037	14.9746	.2884	3674.5628	.3059	3761.3574
61	.1699	6236.6894	.0010	14.9756	.0863	3674.6491	.0920	3761.4494
62	.0667	6236.7561	.0003	14.9759	.0367	3674.6858	.0385	3761.4879
63	.0138	6236.7699	.0000	14.9759	.0070	3674.6928	.0073	3761.4952
64	.0029	6236.7728	0.0000	14.9759	.0015	3674.6943	.0015	3761.4967

3674. BCF--MAX GAS PRODUCED IN SCENARIO

TABLE E-2(7)f

ECONOMIC SUMMARY

PROFIT INDICATORS

DISCOUNTED PRESENT WORTH AT 15.0 PCT. (MM$)	163.50849
DCF RATE OF RETURN (PERCENT)	32.90
PAYOUT TIME (YEARS)	11.12
PROFIT PER INVESTMENT ($/$)	3.300
MAX. UNRECOVERED INVESTMENT (MM$)	59.7135
NET CASH RECOVERY AFTER TAX (MM$)	6230.6705
EXPLORATION EXPENDITURE (MM$)	351.7720
PRODUCTION INVESTMENT (MM$)	1558.5973
TOTAL INVESTMENT (MM$)	1888.2045
OPERATING EXPENSE (MM$)	1429.3769

TABLE E-2(8)a

Standard Scenario at $5.00 and 15%
Base and Advanced Technologies--Greater Southwest
(Behind the Pipe Recompletion)

CASE 1.11 SCENARIO 1 10/10/80 20 YEAR DEVELOPMENT PROGRAM

	YEAR OF DEVELOPMENT			1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	
	LOCATION OF PROSPECTS--																							
1	1601152	SAN JUAN DAKOTA	5.00,15.0	5	7	11	13	15	17	23	23	23	23	23	23	21	17	15	13	11	10	8	7	308
2	1801152	VAL VERDE SONDRA	5.00,15.0	5	7	10	10	13	13	13	12	11	9	7	7	7	7	7	7	7	5	3	2	162
3	2101152	COTTON VALLEY TREND	5.00,15.0	10	15	17	20	25	27	30	35	40	40	50	50	45	40	37	35	32	25	22	20	615
4	2201152	EDWARDS LIME SW	5.00,15.0	20	25	37	50	53	57	63	67	70	75	77	77	77	70	60	50	40	30	27	25	1050
5	2202152	EDWARDS LIME CNTRL	5.00,15.0	5	10	13	15	15	15	17	17	20	20	20	17	17	17	15	15	13	13	12	9	295
6	2301152	VAL VERDE OZONA	5.00,15.0	1	1	1	2	2	3	3	3	3	4	4	4	4	3	3	3	3	3	3	3	56

TABLE E-2(8)b

SUMMARY OF WELL REQUIREMENTS

	CASE	LOCATION OF PROSPECT		NO. PROSP.	WILDCAT WELLS PROD.	WILDCAT WELLS DRY	WILDCAT WELLS TOTAL	W/C SUCCESS RATIO	DEVELOPMENT WELLS PROD.	DEVELOPMENT WELLS DRY	DEVELOPMENT WELLS TOTAL	TOTAL ALL WELLS
1	1601152	SAN JUAN DAKOTA	5.00,15.0	308	170	186	356	.48	7157	1789	8946	9302
2	1801152	VAL VERDE SONDRA	5.00,15.0	162	106	93	199	.53	4131	1032	5163	5362
3	2101152	COTTON VALLEY TREND	5.00,15.0	615	399	273	672	.59	4325	1081	5406	6078
4	2201152	EDWARDS LIME SW	5.00,15.0	1050	844	583	1427	.59	2881	720	3601	5028
5	2202152	EDWARDS LIME CNTRL	5.00,15.0	295	231	168	399	.58	979	244	1223	1622
6	2301152	VAL VERDE OZONA	5.00,15.0	56	52	28	80	.65	843	210	1053	1133

TABLE E-2(8)c

ANNUAL DRILLING SCHEDULE

	PROSPECT	YEAR	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
1	SAN JUAN DAKOTA	5.00,15.0	151	211	332	392	453	513	694	694	694	694	694	694	634	513	453	392	332	302	241	211
2	VAL VERDE SONORA	5.00,15.0	165	231	331	331	430	430	430	397	364	298	231	231	231	231	231	231	231	165	99	66
3	COTTON VALLEY TREND	5.00,15.0	98	148	168	197	247	266	296	345	395	395	494	494	444	395	365	345	316	247	217	197
4	EDWARDS LIME SW	5.00,15.0	96	120	178	241	255	275	304	323	337	362	371	371	371	337	269	241	193	144	130	120
5	EDWARDS LIME CNTRL	5.00,15.0	27	55	71	82	82	82	93	93	110	110	110	93	93	93	82	82	71	71	66	49
6	VAL VERDE OZONA	5.00,15.0	20	20	20	40	40	60	60	60	60	81	81	81	81	60	60	60	60	60	60	60
	TOTAL WELLS IN EACH YEAR		557	785	1100	1283	1507	1626	1877	1912	1960	1940	1981	1964	1854	1629	1480	1351	1203	989	813	703

TABLE E-2(8)d

INVESTMENT REQUIREMENTS AND RESERVE ADDITIONS

YEAR	INVESTMENT (MM$)	GAS RESERVES ADDED (BCF)	CUMULATIVE GAS RESERVES
1	371.2	892.7	892.7
2	551.5	1296.0	2188.7
3	749.8	1755.3	3944.0
4	894.2	2150.9	6094.9
5	1008.6	2398.3	8493.2
6	1074.0	2553.9	11047.1
7	1224.4	2875.9	13923.1
8	1271.8	3039.0	16962.1
9	1355.4	3266.4	20228.5
10	1362.0	3330.0	23558.5
11	1427.7	3547.2	27105.7
12	1386.7	3464.8	30570.5
13	1323.3	3325.4	33895.9
14	1165.9	3019.3	36915.2
15	1072.7	2686.8	39602.0
16	984.9	2430.9	42032.8
17	861.6	2098.3	44131.2
18	721.0	1713.9	45845.1
19	621.2	1500.1	47345.2
20	530.6	1304.7	48649.9
	19988.4	TOTAL INVESTMENT	

TABLE E-2(8)e

CASH FLOW AND PRODUCTION SUMMARY

YEAR	ANNUAL CASH FLOW (MM$)	CUMUL. CASH FLOW (MM$)	ANNUAL NGL PRODN (MMB)	CUMUL. NGL PRODN (MMB)	ANNUAL GAS PRODN (BCF)	CUMUL. GAS PRODN (BCF)	ANNUAL GAS PRODN (BCF EQ1)	CUMUL. GAS PRODN (BCF EQ1)
1	-88.9847	-88.9847	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2	-69.9202	-158.9050	.4308	.4308	49.1095	49.1095	51.6081	51.6081
3	-25.1416	-184.0466	1.0410	1.4710	115.4116	164.5212	121.4494	173.0576
4	74.3125	-109.7341	1.7816	3.2534	202.9121	367.4332	213.2452	386.3028
5	227.0622	117.3282	2.6398	5.8932	307.4408	674.8741	322.7516	709.0544
6	466.0229	523.3511	3.6463	9.5395	416.0697	1090.9438	437.2183	1146.2727
7	577.7582	1101.1093	4.7055	14.2450	526.9152	1617.8590	554.2073	1700.4799
8	792.6009	1893.7102	5.8685	20.1135	649.6287	2267.4877	683.6657	2384.1457
9	1015.9990	2909.7092	7.1251	27.2386	774.4127	3041.9004	815.7100	3199.8842
10	1270.2785	4179.9877	8.4724	35.7110	904.4742	3946.3746	953.6139	4153.4981
11	1516.3208	5696.3085	9.7598	45.4708	1031.7753	4978.1498	1088.3823	5241.8805
12	1797.9178	7494.2263	11.2401	56.7109	1162.2327	6140.3826	1227.4256	6469.3061
13	2071.9551	9566.1814	12.6372	69.3481	1280.5791	7420.9617	1353.8746	7823.1807
14	2345.9510	11912.1324	13.8416	83.1897	1367.2585	8808.2201	1467.5395	9290.7201
15	2584.5361	14496.6625	14.8240	98.0137	1472.3602	10280.5803	1558.3395	10849.0597
16	2774.2512	17270.9137	15.6439	113.6575	1534.7676	11815.3479	1625.5019	12474.5616
17	2934.2667	20205.1024	16.3465	130.0041	1580.9654	13396.3133	1675.7752	14150.3368
18	3057.6338	23262.8162	16.8997	146.9038	1608.0509	15004.3642	1706.0693	15856.4061
19	3130.0745	26392.8907	17.1910	164.0948	1616.4455	16620.8097	1716.1333	17572.5394
20	3178.0364	29570.9271	17.3462	181.4430	1616.7752	18237.5848	1717.3946	19289.9340
21	3315.7302	32886.6273	17.4081	198.8511	1609.1099	19846.6947	1710.0769	21000.0309
22	3228.1158	36114.7431	16.7464	215.5974	1532.7567	21379.4514	1629.8856	22629.9165
23	3125.8274	39240.5704	16.1296	231.7271	1465.4265	22844.8780	1558.9784	24188.8949
24	3069.6239	42250.1943	15.5410	247.2680	1404.4228	24249.3008	1494.5605	25683.4554
25	2897.2484	45147.4428	14.9884	262.2564	1349.5016	25598.8023	1436.4342	27119.8897
26	2791.1622	47938.6049	14.4633	276.7197	1299.0494	26897.8517	1382.9366	28502.8262
27	2669.1865	50627.7914	13.9606	290.6804	1251.9428	28149.7945	1332.9143	29835.7406
28	2590.5611	53218.3525	13.4868	304.1671	1208.0848	29357.8793	1286.3080	31122.0486
29	2497.1202	55715.4727	13.0529	317.2200	1167.4099	30525.2892	1243.1169	32365.1655
30	2408.2367	58123.7094	12.6606	329.8807	1129.4441	31654.7333	1202.8756	33568.0411
31	2323.9044	60447.6139	12.3033	342.1840	1093.6018	32748.3351	1164.9610	34733.0020
32	2243.7074	62691.3213	11.9684	354.1524	1059.2165	33807.5516	1128.6335	35861.6355
33	2164.8846	64856.2060	11.6410	365.7934	1024.8851	34832.4367	1092.4029	36954.0384
34	2083.9161	66940.1221	11.2970	377.0904	989.0500	35821.4867	1054.5727	38008.6111
35	1999.7474	68939.8695	10.9220	388.0124	951.3399	36772.8266	1014.6874	39023.2984
36	1911.4140	70851.2835	10.5168	398.5292	911.3285	37684.1551	972.3258	39995.6242
37	1819.5619	72670.8454	10.0912	408.6204	869.3389	38553.4940	927.8680	40923.4922
38	1725.3180	74396.1835	9.6458	418.2662	825.9858	39379.4798	881.9314	41805.4236
39	1628.5093	76024.6927	9.1800	427.4461	781.2489	40160.7287	834.4926	42639.9162
40	1531.8470	77556.5398	8.6983	436.1444	736.0510	40896.7797	786.5012	43426.4174
41	1434.7833	78991.3231	8.1996	444.3440	690.6675	41587.4472	738.2252	44164.6426
42	1337.4697	80328.7928	7.6812	452.0252	645.1845	42232.6317	689.7354	44854.3780
43	1240.8672	81569.6601	7.1509	459.1761	600.0324	42832.6641	641.5077	45495.8858
44	1145.6357	82715.2956	6.6006	465.7848	555.5765	43388.2407	593.9065	46089.7923
45	1053.4594	83768.7551	6.0642	471.8490	512.5768	43900.8175	547.7492	46637.5415
46	966.7634	84735.5186	5.5425	477.3915	472.1244	44372.9419	504.2710	47141.8125
47	887.7392	85623.2577	5.0645	482.4560	435.2134	44808.1553	464.5873	47606.3998
48	816.7504	86440.0081	4.6332	487.0892	402.0284	45210.1837	428.9009	48035.3008
49	753.7904	87193.7985	4.2436	491.3327	372.5924	45582.7761	397.2053	48432.5060
50	698.7973	87892.5959	3.8957	495.2285	346.8746	45929.6507	369.4699	48801.9759
51	642.5540	88535.1499	3.5427	498.7712	320.1341	46249.7848	340.6819	49142.6579
52	590.1762	89125.3261	3.2194	501.9906	295.0077	46544.7925	313.6800	49456.3379
53	541.0214	89666.3475	2.9260	504.9166	271.1702	46815.9627	288.1408	49744.4787
54	497.8718	90164.2193	2.6671	507.6037	249.8993	47065.8620	265.4847	50009.9634
55	459.2860	90623.5052	2.4850	510.0887	230.5864	47296.4483	244.9996	50254.9630
56	423.5664	91047.0716	2.3073	512.3961	212.5691	47509.0174	225.9516	50480.9147
57	387.2625	91434.3342	2.1271	514.5232	194.2505	47703.2679	206.5878	50687.5024
58	350.2716	91784.6057	1.9378	516.4610	175.6296	47878.8974	186.8686	50874.3710
59	311.7394	92096.3451	1.7371	518.1980	156.2829	48035.1804	166.3579	51040.7289
60	273.0367	92369.3819	1.5405	519.7385	136.8781	48172.0585	145.8128	51186.5417
61	233.0078	92602.3897	1.3234	521.0619	116.8860	48288.9445	124.5616	51311.1033
62	194.1416	92796.5313	1.1086	522.1705	97.4647	48386.4092	103.8946	51414.9980
63	156.8878	92953.4191	.9092	523.0797	78.8189	48465.2281	84.0926	51499.0905
64	123.1716	93076.5907	.7301	523.8099	61.9259	48527.1540	66.1608	51565.2513
65	93.4612	93170.0519	.5659	524.3758	47.0137	48574.1677	50.2959	51615.5472
66	66.9891	93237.0411	.4131	524.7889	33.7110	48607.8787	36.1072	51651.6544
67	44.6614	93281.7025	.2750	525.0639	22.4555	48630.3342	24.0506	51675.7050
68	27.4580	93309.1605	.1684	525.2324	13.7809	48644.1151	14.7579	51690.4628
69	12.7220	93321.8826	.0789	525.3112	6.3795	48650.4946	6.8369	51697.2998

48650. BCF—MAX GAS PRODUCED IN SCENARIO

TABLE E-2(8)f

ECONOMIC SUMMARY

PROFIT INDICATORS

DISCOUNTED PRESENT WORTH AT 15.0 PCT. (MM$)	5609.32980
DCF RATE OF RETURN (PERCENT)	74.40
PAYOUT TIME (YEARS)	3.48
PROFIT PER INVESTMENT ($/$)	4.669
MAX. UNRECOVERED INVESTMENT (MM$)	184.0466
NET CASH RECOVERY AFTER TAX (MM$)	93321.8826
EXPLORATION EXPENDITURE (MM$)	1646.7891
PRODUCTION INVESTMENT (MM$)	18445.1641
TOTAL INVESTMENT (MM$)	19988.4185
OPERATING EXPENSE (MM$)	11453.4954

TABLE E-2(9)a

Standard Scenario at $5.00 and 15%
Base and Advanced Technologies--Southwest
(Behind the Pipe Recompletion)

CASE 1.11 SCENARIO 1 10/09/80 20 YEAR DEVELOPMENT PROGRAM

				YEAR OF DEVELOPMENT	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	
				LOCATION OF PROSPECTS--																					
1	1601152	SAN JUAN DAKOTA	5.00,15.0		1	2	3	5	5	5	5	4	4	4	3	2	2	1	1	0	0	0	0	0	47
2	1801152	VAL VERDE SONDRA	5.00,15.0		1	1	2	3	4	4	4	3	2	2	1	1	1	1	0	0	0	0	0	0	30
3	2101152	COTTON VALLEY TREND	5.00,15.0		2	5	7	10	13	15	15	17	17	17	17	17	15	15	15	15	13	10	8	7	250
4	2201152	EDWARDS LIME SW	5.00,15.0		2	3	5	7	10	10	10	10	10	10	7	7	5	3	3	2	1	1	1	0	107
5	2202152	EDWARDS LIME CNTRL	5.00,15.0		2	5	8	11	11	11	11	11	11	9	7	6	4	2	2	2	2	2	2	2	121
6	2301152	VAL VERDE OZONA	5.00,15.0		2	2	2	2	2	2	1	0	0	0	0	0	0	0	0	0	0	0	0	0	13

TABLE E-2(9)b

SUMMARY OF WELL REQUIREMENTS

	CASE	LOCATION OF PROSPECT		NO. PROSP.	WILDCAT WELLS PROD.	WILDCAT WELLS DRY	WILDCAT WELLS TOTAL	W/C SUCCESS RATIO	DEVELOPMENT WELLS PROD.	DEVELOPMENT WELLS DRY	DEVELOPMENT WELLS TOTAL	TOTAL ALL WELLS
1	1601152	SAN JUAN DAKOTA	5.00,15.0	47	25	28	53	.48	1092	273	1365	1418
2	1801152	VAL VERDE SONDRA	5.00,15.0	30	19	17	36	.53	765	191	956	992
3	2101152	COTTON VALLEY TREND	5.00,15.0	250	162	111	273	.59	1758	439	2197	2470
4	2201152	EDWARDS LIME SW	5.00,15.0	107	86	59	145	.59	293	73	366	511
5	2202152	EDWARDS LIME CNTRL	5.00,15.0	121	95	69	164	.58	401	100	501	665
6	2301152	VAL VERDE OZONA	5.00,15.0	13	12	6	18	.65	195	48	243	261

TABLE E-2(9)c

ANNUAL DRILLING SCHEDULE

	PROSPECT	YEAR	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
1	SAN JUAN DAKOTA	5.00,15.0	30	60	90	151	151	151	151	120	120	120	90	60	60	30	30	0	0	0	0	0
2	VAL VERDE SONDRA	5.00,15.0	33	33	66	99	132	132	132	99	66	66	33	33	33	33	0	0	0	0	0	0
3	COTTON VALLEY TREND	5.00,15.0	19	49	69	98	128	148	148	168	168	168	168	168	148	148	148	148	128	98	79	69
4	EDWARDS LIME SW	5.00,15.0	9	14	24	33	48	48	48	48	48	48	33	33	24	14	14	9	4	4	4	0
5	EDWARDS LIME CNTRL	5.00,15.0	11	27	44	60	60	60	60	60	60	49	38	33	22	11	11	11	11	11	11	11
6	VAL VERDE OZONA	5.00,15.0	40	40	40	40	40	40	20	0	0	0	0	0	0	0	0	0	0	0	0	0
	TOTAL WELLS IN EACH YEAR		142	223	333	481	559	579	559	495	462	451	362	327	287	236	203	168	143	113	94	80

TABLE E-2(9)d

INVESTMENT REQUIREMENTS AND RESERVE ADDITIONS

YEAR	INVESTMENT (MM$)	GAS RESERVES ADDED (BCF)	CUMMULATIVE GAS RESERVES
1	90.2	185.2	185.2
2	171.8	366.3	551.5
3	262.3	561.8	1113.3
4	372.6	794.5	1907.7
5	423.3	931.8	2839.5
6	439.4	975.1	3814.6
7	432.7	966.5	4781.2
8	418.4	967.9	5749.1
9	406.2	950.0	6699.1
10	378.9	895.1	7594.1
11	313.2	752.2	8346.4
12	287.9	709.2	9055.6
13	234.8	574.6	9630.3
14	186.1	467.8	10098.1
15	174.0	450.0	10548.1
16	157.5	416.3	10964.4
17	136.6	354.8	11319.2
18	112.5	289.8	11609.0
19	96.4	246.5	11855.5
20	83.5	206.6	12062.1
	5178.3 TOTAL INVESTMENT		

TABLE E-2(9)e

CASH FLOW AND PRODUCTION SUMMARY

YEAR	ANNUAL CASH FLOW (MM$)	CUMUL. CASH FLOW (MM$)	ANNUAL NGL PRODN (MMB)	CUMUL. NGL PRODN (MMB)	ANNUAL GAS PRODN (BCF)	CUMUL. GAS PRODN (BCF)	ANNUAL GAS PRODN (BCF EQI)	CUMUL. GAS PRODN (BCF EQI)
1	-20.7557	-20.7557	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2	-30.0397	-50.7953	.0964	.0964	9.7327	9.7327	10.2919	10.2919
3	-27.6502	-78.4455	.2901	.3865	28.3968	38.1295	30.0793	40.3712
4	-13.2092	-91.6547	.5612	.9477	56.0888	94.2183	59.3440	99.7152
5	31.8859	-59.7688	.9374	1.8851	93.8889	188.1072	99.3256	199.0409
6	100.6421	40.8733	1.3990	3.2841	136.2869	324.3941	144.4010	343.4419
7	181.0194	221.8927	1.9000	5.1841	178.2218	502.6159	189.2419	532.6837
8	263.4817	485.3744	2.3809	7.5650	217.7084	720.3243	231.5177	764.2014
9	346.4014	831.7757	2.6812	10.4463	255.5454	975.8697	272.2566	1036.4580
10	429.9292	1261.7050	3.3545	13.8007	291.0411	1266.9108	310.4971	1346.9551
11	516.7279	1778.4329	3.8038	17.6046	321.8206	1588.7314	343.8828	1690.8379
12	582.1190	2360.5519	4.2046	21.8092	343.3118	1932.0433	367.6986	2058.5365
13	647.3688	3007.9207	4.5798	26.3890	361.9416	2293.9849	388.5047	2447.0412
14	696.4920	3704.4126	4.6688	31.0578	372.4451	2666.4301	400.6839	2847.7251
15	724.2443	4428.6569	5.1266	36.3844	376.7882	3043.2182	406.5225	3254.2475
16	748.8797	5177.5366	5.3637	41.7481	381.1820	3424.4002	412.2915	3666.5390
17	768.3048	5945.8414	5.5835	47.3316	383.9165	3808.3167	416.3009	4082.8399
18	781.0507	6726.8921	5.7386	53.0702	383.9141	4192.2309	417.1980	4500.0379
19	785.9662	7512.8584	5.8102	58.8804	381.6023	4573.8331	415.3014	4915.3394
20	785.8782	8298.7366	5.8295	64.7099	377.9823	4951.8956	411.8738	5327.2131
21	796.9726	9095.7092	5.8219	70.5318	373.0071	5324.9029	406.7742	5733.9873
22	776.1963	9871.9055	5.6230	76.1548	358.7818	5663.6848	391.3953	6125.3826
23	753.4314	10625.3369	5.4366	81.5914	345.8662	6029.5509	377.1981	6502.7810
24	728.8202	11354.1571	5.2551	86.8465	333.7606	6363.3115	364.2401	6867.0211
25	704.7726	12058.9297	5.0800	91.9265	322.4216	6685.7331	351.8858	7218.9069
26	681.3790	12740.3087	4.9106	96.8372	311.6490	6997.3821	340.1307	7559.0376
27	658.6380	13398.9467	4.7474	101.5846	301.4068	7298.7889	328.9418	7887.9794
28	636.4339	14035.3806	4.5933	106.1779	291.7603	7590.5492	318.4014	8206.3807
29	615.2232	14650.6038	4.4521	110.6299	282.7104	7873.2596	308.5324	8514.9131
30	594.9609	15245.5647	4.3242	114.9541	274.1430	8147.4026	299.2233	8814.1364
31	575.3942	15820.9589	4.2076	119.1617	265.9065	8413.3091	290.3107	9104.4471
32	556.3803	16377.3392	4.0983	123.2600	257.7829	8671.0920	281.5530	9386.0001
33	537.3669	16914.7061	3.9910	127.2511	249.5015	8920.5935	272.6495	9658.6496
34	517.5374	17432.2454	3.8793	131.1304	240.7529	9161.3463	263.2531	9921.9027
35	495.9458	17928.1912	3.7543	134.8848	231.1236	9392.4699	252.8987	10174.8015
36	472.0466	18400.2378	3.6119	138.4967	220.3543	9612.8242	241.3036	10416.1050
37	446.2991	18846.5370	3.4529	141.9496	208.6782	9821.5024	228.7052	10644.8102
38	418.9130	19265.4500	3.2781	145.2277	196.2133	10017.7157	215.2260	10860.0362
39	390.9004	19656.3504	3.0909	148.3186	183.4420	10201.1577	201.3695	11061.4057
40	363.3474	20019.6978	2.8991	151.2177	170.8126	10371.9703	187.6272	11249.0329
41	336.4294	20356.1272	2.7053	153.9229	158.4902	10530.4605	174.1807	11423.2136
42	310.7057	20666.8329	2.5128	156.4357	146.7316	10677.1921	161.3058	11584.5194
43	286.5623	20953.3952	2.3247	158.7604	135.7206	10812.9127	149.2036	11733.7230
44	264.2061	21217.6014	2.1431	160.9035	125.5536	10938.4663	137.9838	11871.7067
45	243.3175	21460.9189	1.9683	162.8718	116.0705	11054.5368	127.4864	11999.1932
46	224.5194	21685.4403	1.8044	164.6762	107.5529	11162.0897	118.0185	12117.2117
47	207.5208	21892.9612	1.6518	166.3280	99.8699	11261.9596	109.4505	12226.6622
48	191.9020	22084.8631	1.5085	167.8365	92.8258	11354.7854	101.5750	12328.2372
49	177.3231	22262.1863	1.3726	169.2091	86.2529	11441.0383	94.2137	12422.4509
50	164.0855	22426.2718	1.2488	170.4579	80.2703	11521.3086	87.5135	12509.9645
51	150.4676	22576.7394	1.1298	171.5877	73.9392	11595.2478	80.4918	12590.4563
52	137.1851	22713.9245	1.0223	172.6099	67.6756	11662.9234	73.6047	12664.0610
53	123.8924	22837.8168	.9234	173.5333	61.2924	11724.2158	66.6479	12730.7089
54	110.8007	22948.6971	.8357	174.3690	54.8952	11779.1110	59.7422	12790.4511
55	96.2646	23046.9617	.7565	175.1255	48.5976	11827.7086	52.9854	12843.4365
56	86.4530	23133.4347	.6827	175.8082	42.6481	11870.3566	46.6077	12890.0442
57	75.3468	23208.7815	.6117	176.4215	37.0697	11907.4263	40.6265	12930.6707
58	64.7124	23273.4939	.5441	176.9656	31.7737	11939.2000	34.9296	12965.6003
59	54.7172	23328.2111	.4791	177.4447	26.8198	11966.0197	29.5985	12995.1987
60	45.4326	23373.6437	.4153	177.8599	22.2152	11988.2350	24.6238	13019.8226
61	37.7934	23411.4371	.3574	178.2173	18.4519	12006.6868	20.5246	13040.3471
62	30.5406	23441.9777	.3005	178.5178	14.8789	12021.5657	16.6219	13056.9690
63	24.6762	23466.6539	.2510	178.7688	11.9908	12033.5565	13.4466	13070.4157
64	19.7201	23486.3740	.2027	178.9716	9.5550	12043.1115	10.7309	13081.1465
65	15.1363	23501.5103	.1577	179.1292	7.3313	12050.4428	8.2459	13089.3924
66	10.8118	23512.3220	.1130	179.2423	5.2368	12055.6796	5.8922	13095.2846
67	7.2163	23519.5403	.0745	179.3167	3.4980	12059.1776	3.9301	13099.2147
68	4.3403	23523.8807	.0447	179.3615	2.1039	12061.2811	2.3628	13101.5775
69	1.9361	23525.8168	.0207	179.3822	.9370	12062.2181	1.0573	13102.6348

12062. BCF--MAX GAS PRODUCED IN SCENARIO

TABLE E-2(9)f

ECONOMIC SUMMARY

PROFIT INDICATORS

DISCOUNTED PRESENT WORTH AT 15.0 PCT. (MM$)	1551.25260
DCF RATE OF RETURN (PERCENT)	64.30
PAYOUT TIME (YEARS)	4.59
PROFIT PER INVESTMENT ($/$)	4.543
MAX. UNRECOVERED INVESTMENT (MM$)	91.6547
NET CASH RECOVERY AFTER TAX (MM$)	23525.8168
EXPLORATION EXPENDITURE (MM$)	400.6538
PRODUCTION INVESTMENT (MM$)	4803.2804
TOTAL INVESTMENT (MM$)	5178.3006
OPERATING EXPENSE (MM$)	3027.0293

TABLE E-3(1)a

Standard Scenario at $3.50 and 15%
Base and Advanced Technologies--Northern Great Plains/Williston

				20 YEAR DEVELOPMENT PROGRAM																			
	YEAR OF DEVELOPMENT			1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	
	LOCATION OF PROSPECTS--																							
1	1201142	NGP WILL MOWRY	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	1202142	NGP,MOWRY + GRNHORN	15.0,3.50	0	0	0	2	2	3	2	1	0	0	0	0	0	0	0	0	0	0	0	0	10
3	1203142	NGP,MOWRY + CARLILE	15.0,3.50	0	0	1	1	2	5	4	2	0	0	0	0	0	0	0	0	0	0	0	0	15
4	1204142	NGP,MOWRY + G,CARLE	15.0,3.50	1	1	2	3	5	10	8	5	0	0	0	0	0	0	0	0	0	0	0	0	35
5	1205142	NGP,MRY GRNHN,C,EGLE	15.0,3.50	5	10	12	15	15	13	10	8	0	0	0	0	0	0	0	0	0	0	0	0	88
6	1206142	NGP,MRY,GRHN,EAGLE	15.0,3.50	0	0	0	2	3	5	5	3	0	0	0	0	0	0	0	0	0	0	0	0	18
7	1207142	NGP,MOWRY + JUDITH	15.0,3.50	0	0	0	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	5
8	1208142	NGP,MOWRY,CAL, EAGLE	15.0,3.50	2	5	7	7	7	7	7	7	0	0	0	0	0	0	0	0	0	0	0	0	49
9	1209142	NGP,MRY,CAL,EGL,JDTH	15.0,3.50	0	2	5	5	7	7	4	2	0	0	0	0	0	0	0	0	0	0	0	0	32
10	1210142	NGP,MY,GH,CAL,EGL, JD	15.0,3.50	1	1	3	3	5	5	4	4	0	0	0	0	0	0	0	0	0	0	0	0	26
11	1211142	NGP,MRY,CAL, JUD RIV	15.0,3.50	0	0	2	2	2	3	3	3	0	0	0	0	0	0	0	0	0	0	0	0	15
12	1212142	NGP,GREENHORN	15.0,3.50	0	0	0	0	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	3
13	1213142	NGP,GRNHORN + CALILE	15.0,3.50	0	0	0	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	5
14	1214142	NGP,GRNHORN + EAGLE	15.0,3.50	0	1	1	1	2	3	3	3	0	0	0	0	0	0	0	0	0	0	0	0	14
15	1215142	NGP,GRNHN,CARL, EGLE	15.0,3.50	0	0	1	1	3	3	3	3	0	0	0	0	0	0	0	0	0	0	0	0	14
16	1216142	NGP, CARLILE	15.0,3.50	0	0	0	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3
17	1217142	NGP,NIOBRARA	15.0,3.50	1	1	2	3	3	3	3	3	1	0	0	0	0	0	0	0	0	0	0	0	20
18	1218142	NGP,CARL + EAGLE	15.0,3.50	0	0	0	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3
19	1219142	NGP,WILLS JUD.RIV	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
20	1220142	NGP,WILLS CARL+NIOB	15.0,3.50	0	0	1	1	2	2	3	3	0	0	0	0	0	0	0	0	0	0	0	0	12
21	1201242	NGP WILL MOWRY	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
22	1202242	NGP,MOWRY +GRNHORN	15.0,3.50	0	0	0	0	0	2	3	4	4	4	7	7	7	7	9	9	9	9	9	9	97
23	1203242	NGP,MOWRY +CARLILE	15.0,3.50	0	0	0	0	1	4	5	5	5	5	5	6	6	9	9	9	9	9	9	9	105
24	1204242	NGP,MRY +GRNHN+CARL	15.0,3.50	0	0	0	1	2	8	8	16	16	16	18	18	23	23	26	26	30	30	30	30	321
25	1205242	NGP,MRY,GRHN,CAL,EGL	15.0,3.50	0	0	3	3	10	13	16	18	26	26	26	26	26	26	26	30	30	30	30	30	395
26	1206242	NGP,MRY,GRHN,EAGLE	15.0,3.50	0	0	0	1	2	4	5	7	10	10	10	10	10	10	8	8	8	8	8	8	127
27	1207242	NGP,MONRY + JUDITH	15.0,3.50	0	0	0	0	0	0	1	2	5	5	5	7	7	10	10	12	12	12	12	12	112
28	1208242	NGP,MONRY,CARL,EAGLE	15.0,3.50	0	0	1	2	2	4	4	7	7	7	9	9	9	11	11	15	15	15	15	15	158
29	1209242	NGP,MRY,CAL,EGL,JDTH	15.0,3.50	0	0	0	1	3	7	10	13	15	17	17	21	21	25	25	25	27	27	27	27	308
30	1210242	NGP,MY,GN,CAL,EG,JDT	15.0,3.50	0	0	0	0	2	5	6	8	10	10	13	13	13	15	15	15	15	17	17	17	191
31	1211242	NGP,MRY,CAL, JUD.RIV	15.0,3.50	0	0	0	0	1	3	6	7	10	10	10	10	12	12	12	12	14	14	14	14	161
32	1212242	NGP,GREENHORN	15.0,3.50	0	0	0	0	0	0	0	1	1	1	2	2	2	2	2	2	2	2	2	2	23
33	1213242	NGP,GRNHORN +CALILE	15.0,3.50	0	0	0	0	0	1	1	1	2	2	2	2	2	3	3	3	3	3	3	3	34
34	1214242	NGP,GRNHORN + EAGLE	15.0,3.50	0	0	0	0	1	3	5	10	13	13	13	13	13	13	6	0	0	0	0	0	103
35	1215242	NGP,GRHN,CARL,EAGLE	15.0,3.50	0	0	0	0	1	3	5	7	10	10	10	10	7	7	4	4	4	0	0	0	82
36	1216242	NGP, CARLILE	15.0,3.50	0	0	0	0	0	0	0	0	1	1	1	1	1	2	2	2	2	2	2	2	19
37	1217242	NGP, NIOBRARA	15.0,3.50	0	0	1	1	5	7	12	14	18	20	25	35	37	40	40	42	42	43	43	43	468
38	1218242	NGP, CARL + EAGLE	15.0,3.50	0	0	0	0	0	1	2	2	2	3	3	3	3	3	2	2	2	2	2	2	34
39	1219242	NGP,WILLS JUD.RIV	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
40	1220242	NGP,WILLS CARL+NIOB	15.0,3.50	0	0	0	0	1	2	4	4	7	7	7	7	9	9	4	3	2	0	0	0	66

TABLE E-3(1)b

SUMMARY OF WELL REQUIREMENTS

	CASE	LOCATION OF PROSPECT		NO. PROSP.	WILDCAT WELLS			W/C SUCCESS RATIO	DEVELOPMENT WELLS			TOTAL ALL WELLS
					PROD.	DRY	TOTAL		PROD.	DRY	TOTAL	
1	1201142	NGP WILL MOWRY	15.0,3.50	0	0	0	0	I	0	0	0	0
2	1202142	NGP,MOWRY + GRNHORN	15.0,3.50	10	3	16	19	.16	66	16	82	101
3	1203142	NGP,MOWRY + CARLILE	15.0,3.50	15	5	22	27	.21	119	29	148	175
4	1204142	NGP,MOWRY + G,CARLE	15.0,3.50	35	12	54	66	.19	182	45	227	293
5	1205142	NGP,MRY GRNHN,C,EGLE	15.0,3.50	88	37	129	166	.23	374	93	467	633
6	1206142	NGP,MRY,GRHN,EAGLE	15.0,3.50	18	5	28	33	.17	111	27	138	171
7	1207142	NGP,MOWRY + JUDITH	15.0,3.50	5	1	8	9	.13	34	8	42	51
8	1208142	NGP,MOWRY,CAL, EAGLE	15.0,3.50	49	20	71	91	.22	239	59	298	389
9	1209142	NGP,MRY,CAL,EGL,JDTH	15.0,3.50	32	12	48	60	.21	138	34	172	232
10	1210142	NGP,MY,GH,CAL,EGL, JD	15.0,3.50	26	10	38	48	.22	55	13	68	116
11	1211142	NGP,MRY,CAL, JUD RIV	15.0,3.50	15	5	22	27	.20	112	28	140	167
12	1212142	NGP,GREENHORN	15.0,3.50	3	0	5	5	.10	17	4	21	26
13	1213142	NGP,GRNHORN + CALILE	15.0,3.50	5	1	7	8	.19	43	10	53	61
14	1214142	NGP,GRNHORN + EAGLE	15.0,3.50	14	5	21	26	.19	90	22	112	138
15	1215142	NGP,GRNHN,CARL, EGLE	15.0,3.50	14	4	21	25	.18	54	13	67	92
16	1216142	NGP, CARLILE	15.0,3.50	3	0	4	4	.14	33	8	41	45
17	1217142	NGP,NIOBRARA	15.0,3.50	20	3	35	38	.10	40	10	50	88
18	1218142	NGP,CARL + EAGLE	15.0,3.50	3	0	4	4	.16	17	4	21	25
19	1219142	NGP#WILLS JUD.RIV	15.0,3.50	0	0	0	0	I	0	0	0	0
20	1220142	NGP#WILLS CARL+NIOB	15.0,3.50	12	3	19	22	.16	35	8	43	65
21	1201242	NGP WILL MOWRY	15.0,3.50	0	0	0	0	I	0	0	0	0
22	1202242	NGP,MOWRY +GRNHORN	15.0,3.50	97	32	155	187	.17	347	86	433	620
23	1203242	NGP,MOWRY +CARLILE	15.0,3.50	105	41	158	199	.21	433	108	541	740
24	1204242	NGP,MRY +GRNHN+CARL	15.0,3.50	321	119	498	617	.19	849	224	[illegible]	[illegible]
25	1205242	NGP,MRY,GRHN,CAL,EGL	15.0,3.50	395	168	579	747	.23	893	223	[illegible]	[illegible]
26	1206242	NGP,MRY,GRHN,EAGLE	15.0,3.50	127	39	200	239	.17	445	111	556	795
27	1207242	NGP,MONRY + JUDITH	15.0,3.50	112	36	175	211	.17	577	144	721	932
28	1208242	NGP,MONRY,CARL,EAGLE	15.0,3.50	158	52	245	297	.18	276	69	345	642
29	1209242	NGP,MRY,CAL,EGL,JDTH	15.0,3.50	308	120	462	582	.21	752	188	940	1522
30	1210242	NGP,MY,GN,CAL,EG,JDT	15.0,3.50	191	80	279	359	.22	377	94	471	830
31	1211242	NGP,MRY,CAL, JUD.RIV	15.0,3.50	161	61	243	304	.20	672	168	840	1144
32	1212242	NGP,GREENHORN	15.0,3.50	23	6	36	42	.15	145	36	181	223
33	1213242	NGP,GRNHORN +CALILE	15.0,3.50	34	14	49	63	.22	206	51	257	320
34	1214242	NGP,GRNHORN + EAGLE	15.0,3.50	103	48	144	192	.25	616	154	770	962
35	1215242	NGP,GRHN,CARL,EAGLE	15.0,3.50	82	34	120	154	.22	294	73	367	521
36	1216242	NGP, CARLILE	15.0,3.50	19	5	30	35	.14	108	27	135	170
37	1217242	NGP, NIOBRARA	15.0,3.50	468	90	822	912	.10	473	118	591	1503
38	1218242	NGP, CARL + EAGLE	15.0,3.50	34	10	54	64	.16	113	28	141	205
39	1219242	NGP#WILLS JUD.RIV	15.0,3.50	0	0	0	0	I	0	0	0	0
40	1220242	NGP#WILLS CARL+NIOB	15.0,3.50	66	26	98	124	.21	227	56	283	407

TABLE E-3(1)c

ANNUAL DRILLING SCHEDULE

	PROSPECT	YEAR	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
1	NGP WILL MOWRY	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	NGP,MOWRY + GRNHORN	15.0,3.50	0	0	0	20	20	30	20	10	0	0	0	0	0	0	0	0	0	0	0	0
3	NGP,MOWRY + CARLILE	15.0,3.50	0	0	11	11	23	59	47	23	0	0	0	0	0	0	0	0	0	0	0	0
4	NGP,MOWRY + G,CARLE	15.0,3.50	8	8	16	25	42	84	67	42	0	0	0	0	0	0	0	0	0	0	0	0
5	NGP,MRY GRNHN,C,EGLE	15.0,3.50	36	72	86	108	108	93	72	57	0	0	0	0	0	0	0	0	0	0	0	0
6	NGP,MRY,GRHN,EAGLE	15.0,3.50	0	0	0	19	28	48	48	28	0	0	0	0	0	0	0	0	0	0	0	0
7	NGP,MOWRY + JUDITH	15.0,3.50	0	0	0	10	10	10	10	10	0	0	0	0	0	0	0	0	0	0	0	0
8	NGP,MOWRY,CAL, EAGLE	15.0,3.50	15	39	55	55	55	55	55	55	0	0	0	0	0	0	0	0	0	0	0	0
9	NGP,MRY,CAL,EGL,JDTH	15.0,3.50	0	14	36	36	51	51	29	14	0	0	0	0	0	0	0	0	0	0	0	0
10	NGP,MY,GH,CAL,EGL, JD	15.0,3.50	4	4	13	13	22	22	18	18	0	0	0	0	0	0	0	0	0	0	0	0
11	NGP,MRY,CAL, JUD RIV	15.0,3.50	0	0	22	22	22	33	33	33	0	0	0	0	0	0	0	0	0	0	0	0
12	NGP,GREENHORN	15.0,3.50	0	0	0	0	0	9	9	9	0	0	0	0	0	0	0	0	0	0	0	0
13	NGP,GRNHORN + CALILE	15.0,3.50	0	0	0	12	12	12	12	12	0	0	0	0	0	0	0	0	0	0	0	0
14	NGP,GRNHORN + EAGLE	15.0,3.50	0	9	9	9	19	29	29	29	0	0	0	0	0	0	0	0	0	0	0	0
15	NGP,GRNHN,CARL, EGLE	15.0,3.50	0	0	9	9	27	27	27	27	0	0	0	0	0	0	0	0	0	0	0	0
16	NGP, CARLILE	15.0,3.50	0	0	0	15	15	15	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17	NGP,NIOBRARA	15.0,3.50	4	4	8	13	13	13	13	13	0	0	0	0	0	0	0	0	0	0	0	0
18	NGP,CARL + EAGLE	15.0,3.50	0	0	0	9	9	9	0	0	0	0	0	0	0	0	0	0	0	0	0	0
19	NGP*WILLS JUD.RIV	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
20	NGP*WILLS CARL+NIOB	15.0,3.50	0	0	5	5	11	11	16	16	0	0	0	0	0	0	0	0	0	0	0	0
21	NGP WILL MOWRY	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
22	NGP,MOWRY +GRNHORN	15.0,3.50	0	0	0	0	0	12	19	25	25	25	44	44	44	44	44	57	57	57	57	57
23	NGP,MOWRY +CARLILE	15.0,3.50	0	0	0	0	7	26	35	35	35	35	35	42	42	63	63	63	63	63	63	63
24	NGP,MRY +GRNHN+CARL	15.0,3.50	0	0	0	5	10	43	43	86	86	86	97	97	124	124	141	141	162	162	162	162
25	NGP,MRY,GRHN,CAL,EGL	15.0,3.50	0	0	14	14	47	61	75	89	122	122	122	122	122	122	122	141	141	141	141	141
26	NGP,MRY,GRHN,EAGLE	15.0,3.50	0	0	0	6	12	25	31	43	62	62	62	62	62	62	50	50	50	50	50	50
27	NGP,MONRY + JUDITH	15.0,3.50	0	0	0	0	0	0	8	16	41	41	41	58	58	83	83	100	100	100	100	100
28	NGP,MONRY,CARL,EAGLE	15.0,3.50	0	0	4	8	8	16	16	28	28	28	36	36	36	44	44	61	61	61	61	61
29	NGP,MRY,CAL,EGL,JDTH	15.0,3.50	0	0	0	4	14	34	49	64	74	84	84	103	103	123	123	123	133	133	133	133
30	NGP,MY,GN,CAL,EG,JDT	15.0,3.50	0	0	0	0	8	21	26	34	43	43	56	56	56	65	65	65	65	74	74	74
31	NGP,MRY,CAL, JUD.RIV	15.0,3.50	0	0	0	0	7	21	42	49	71	71	71	71	85	85	85	85	99	99	99	99
32	NGP,GREENHORN	15.0,3.50	0	0	0	0	0	0	0	9	9	9	19	19	19	19	19	19	19	19	19	19
33	NGP,GRNHORN +CALILE	15.0,3.50	0	0	0	0	0	9	9	9	18	18	18	18	18	28	28	28	28	28	28	28
34	NGP,GRNHORN + EAGLE	15.0,3.50	0	0	0	0	9	28	46	93	121	121	121	121	121	121	56	0	0	0	0	0
35	NGP,GRHN,CARL,EAGLE	15.0,3.50	0	0	0	0	6	19	31	44	63	63	63	63	44	44	25	25	25	0	0	0
36	NGP, CARLILE	15.0,3.50	0	0	0	0	0	0	0	0	9	9	9	9	9	18	18	18	18	18	18	18
37	NGP, NIOBRARA	15.0,3.50	0	0	3	3	16	22	38	44	57	64	80	112	118	128	128	134	134	138	138	138
38	NGP, CARL + EAGLE	15.0,3.50	0	0	0	0	0	6	12	12	12	18	18	18	18	18	12	12	12	12	12	12
39	NGP*WILLS JUD.RIV	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
40	NGP*WILLS CARL+NIOB	15.0,3.50	0	0	0	0	6	12	24	24	43	43	43	43	55	55	24	18	12	0	0	0
	TOTAL WELLS IN EACH YEAR		67	150	291	431	637	967	1009	1096	923	942	1019	1094	1134	1246	1130	1140	1179	1155	1155	1155

TABLE E-3(1)d

INVESTMENT REQUIREMENTS AND RESERVE ADDITIONS

YEAR	INVESTMENT (MM$)	GAS RESERVES ADDED (BCF)	CUMMULATIVE GAS RESERVES
1	20.7	76.7	76.7
2	45.9	165.2	241.9
3	93.5	321.4	563.3
4	136.1	442.9	1006.1
5	224.7	705.2	1711.3
6	360.3	1089.3	2800.6
7	405.4	1202.3	4002.9
8	471.4	1379.5	5382.3
9	473.7	1317.9	6700.3
10	484.9	1345.4	8045.7
11	522.0	1452.1	9497.8
12	560.0	1552.6	11050.4
13	575.9	1608.7	12659.1
14	631.9	1753.8	14412.8
15	578.0	1617.6	16030.4
16	587.2	1652.5	17682.9
17	606.9	1711.1	19394.0
18	594.2	1680.9	21074.9
19	594.2	1680.9	22755.7
20	594.2	1680.9	24436.6
	8561.2	TOTAL INVESTMENT	

TABLE E-3(1)e

CASH FLOW AND PRODUCTION SUMMARY

YEAR	ANNUAL CASH FLOW (MM$)	CUMUL. CASH FLOW (MM$)	ANNUAL NGL PRODN (MMB)	CUMUL. NGL PRODN (MMB)	ANNUAL GAS PRODN (BCF)	CUMUL. GAS PRODN (BCF)	ANNUAL GAS PRODN (BCF EQI)	CUMUL. GAS PRODN (BCF EQI)
1	-.4455	-.4455	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2	-3.1426	-3.5881	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
3	-8.4884	-12.0765	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
4	-15.0442	-27.1207	0.0000	0.0000	.6783	.6783	.6783	.6783
5	-26.2778	-53.3985	0.0000	0.0000	3.2293	3.9076	3.2293	3.9076
6	-37.6697	-91.0682	0.0000	0.0000	10.3926	14.3002	10.3926	14.3002
7	-56.7266	-147.7949	0.0000	0.0000	23.2598	37.5600	23.2598	37.5600
8	-63.2859	-211.0808	0.0000	0.0000	44.6638	82.2238	44.6638	82.2238
9	-55.1124	-266.1932	0.0000	0.0000	76.6740	158.8978	76.6740	158.8978
10	-38.7155	-304.9087	0.0000	0.0000	121.4817	280.3795	121.4817	280.3795
11	4.6912	-300.2175	0.0000	0.0000	179.0462	459.4257	179.0462	459.4257
12	62.1855	-238.0320	0.0000	0.0000	242.7835	702.2092	242.7835	702.2092
13	132.8273	-105.4047	0.0000	0.0000	307.0323	1009.2415	307.0323	1009.2415
14	204.7383	99.3336	0.0000	0.0000	368.5697	1377.8112	368.5697	1377.8112
15	274.8758	374.2095	0.0000	0.0000	429.1402	1806.9514	429.1402	1806.9514
16	343.7023	717.9118	0.0000	0.0000	491.1922	2298.1436	491.1922	2298.1436
17	427.0244	1144.9362	0.0000	0.0000	556.0537	2854.1973	556.0537	2854.1973
18	496.5331	1641.4692	0.0000	0.0000	620.9163	3475.1136	620.9163	3475.1136
19	563.8730	2225.3423	0.0000	0.0000	685.3208	4160.4343	685.3208	4160.4343
20	669.2300	2894.5723	0.0000	0.0000	745.6503	4906.0846	745.6503	4906.0846
21	755.8248	3650.3971	0.0000	0.0000	803.4960	5709.5806	803.4960	5709.5806
22	882.1753	4532.5724	0.0000	0.0000	859.9308	6569.5114	859.9308	6569.5114
23	1048.2878	5580.8602	0.0000	0.0000	914.2806	7483.7920	914.2806	7483.7920
24	1085.8140	6666.6742	0.0000	0.0000	944.9556	8428.7476	944.9556	8428.7476
25	1187.5498	7854.2240	0.0000	0.0000	950.1494	9378.8970	950.1494	9378.8970
26	1199.9232	9054.1473	0.0000	0.0000	915.9263	10294.8233	915.9263	10294.8233
27	1165.8043	10219.9516	0.0000	0.0000	871.2551	11166.0784	871.2551	11166.0784
28	1112.7282	11332.6798	0.0000	0.0000	830.7700	11996.8483	830.7700	11996.8483
29	1066.4313	12399.1111	0.0000	0.0000	797.4763	12794.3246	797.4763	12794.3246
30	1025.9083	13425.0194	0.0000	0.0000	768.5291	13562.8537	768.5291	13562.8537
31	989.3194	14414.3388	0.0000	0.0000	742.4824	14305.3361	742.4824	14305.3361
32	955.2234	15369.5622	0.0000	0.0000	718.6988	15024.0349	718.6988	15024.0349
33	923.5654	16293.1276	0.0000	0.0000	696.9745	15721.0094	696.9745	15721.0094
34	894.0764	17187.2040	0.0000	0.0000	676.9245	16397.9339	676.9245	16397.9339
35	866.4969	18053.7010	0.0000	0.0000	658.0180	17055.9520	658.0180	17055.9520
36	839.9622	18893.6632	0.0000	0.0000	639.4194	17695.3713	639.4194	17695.3713
37	813.3860	19707.0492	0.0000	0.0000	620.3990	18315.7703	620.3990	18315.7703
38	785.5905	20492.6397	0.0000	0.0000	600.2193	18915.9896	600.2193	18915.9896
39	755.5340	21248.1787	0.0000	0.0000	578.1649	19494.1545	578.1649	19494.1545
40	722.3106	21970.4893	0.0000	0.0000	553.5364	20047.6909	553.5364	20047.6909
41	685.6531	22656.1424	0.0000	0.0000	526.1439	20573.8348	526.1439	20573.8348
42	645.6101	23301.7525	0.0000	0.0000	496.0422	21069.8770	496.0422	21069.8770
43	602.8999	23904.6524	0.0000	0.0000	463.7933	21533.6703	463.7933	21533.6703
44	558.1510	24462.8034	0.0000	0.0000	429.9381	21963.6085	429.9381	21963.6085
45	511.8672	24974.6706	0.0000	0.0000	394.8641	22358.4725	394.8641	22358.4725
46	463.9564	25438.6270	0.0000	0.0000	358.5079	22716.9804	358.5079	22716.9804
47	414.7943	25853.4213	0.0000	0.0000	321.1278	23038.1082	321.1278	23038.1082
48	365.4227	26218.8440	0.0000	0.0000	283.4903	23321.5985	283.4903	23321.5985
49	315.3042	26534.1482	0.0000	0.0000	245.2241	23566.8226	245.2241	23566.8226
50	265.7000	26799.8483	0.0000	0.0000	207.2375	23774.0601	207.2375	23774.0601
51	217.6566	27017.5049	0.0000	0.0000	170.3389	23944.3990	170.3389	23944.3990
52	172.4224	27189.9273	0.0000	0.0000	135.4384	24079.8374	135.4384	24079.8374
53	130.3585	27320.2858	0.0000	0.0000	102.8381	24182.6755	102.8381	24182.6755
54	92.7120	27412.9978	0.0000	0.0000	73.4813	24256.1568	73.4813	24256.1568
55	60.9384	27473.9362	0.0000	0.0000	48.5793	24304.7361	48.5793	24304.7361
56	36.7818	27510.7181	0.0000	0.0000	29.4377	24334.1739	29.4377	24334.1739
57	21.1319	27531.8499	0.0000	0.0000	17.0245	24351.1984	17.0245	24351.1984
58	11.9249	27543.7798	0.0000	0.0000	9.6384	24360.8367	9.6384	24360.8367
59	8.6800	27552.4598	0.0000	0.0000	7.0485	24367.8852	7.0485	24367.8852
60	7.3847	27559.8445	0.0000	0.0000	6.0232	24373.9084	6.0232	24373.9084
61	6.4706	27566.3151	0.0000	0.0000	5.3057	24379.2141	5.3057	24379.2141
62	5.6907	27572.0058	0.0000	0.0000	4.6886	24383.9027	4.6886	24383.9027
63	4.6498	27576.6556	0.0000	0.0000	4.0160	24387.9186	4.0160	24387.9186
64	4.2269	27581.0825	0.0000	0.0000	3.5014	24391.4200	3.5014	24391.4200
65	3.5785	27584.6610	0.0000	0.0000	2.9651	24394.3851	2.9651	24394.3851
66	2.9412	27587.6022	0.0000	0.0000	2.4370	24396.8221	2.4370	24396.8221
67	2.2059	27589.8081	0.0000	0.0000	1.8278	24398.6499	1.8278	24398.6499
68	1.4706	27591.2787	0.0000	0.0000	1.2185	24399.8684	1.2185	24399.8684
69	.7353	27592.0140	0.0000	0.0000	.6093	24400.4776	.6093	24400.4776

24400. BCF--MAX GAS PRODUCED IN SCENARIO

TABLE E-3(1)f

ECONOMIC SUMMARY

PROFIT INDICATORS

DISCOUNTED PRESENT WORTH AT 15.0 PCT. (MM$)	612.64211
DCF RATE OF RETURN (PERCENT)	31.10
PAYOUT TIME (YEARS)	12.51
PROFIT PER INVESTMENT ($/$)	3.223
MAX. UNRECOVERED INVESTMENT (MM$)	304.9087
NET CASH RECOVERY AFTER TAX (MM$)	27592.0140
EXPLORATION EXPENDITURE (MM$)	3374.7103
PRODUCTION INVESTMENT (MM$)	5422.5420
TOTAL INVESTMENT (MM$)	8561.2067
OPERATING EXPENSE (MM$)	7604.0993

TABLE E-4(1)a

Standard Scenario at $3.50 and 15%
Base and Advanced Technologies--Rocky Mountains

20 YEAR DEVELOPMENT PROGRAM

	YEAR OF DEVELOPMENT			1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	
	LOCATION OF PROSPECTS--																							
1	0502142	DENVER,B	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	0801142	GGR LWN 1 ALMOND A	15.0,3.50	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	7
3	0802142	GGR,LEW 1, E,R,S,B	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4	0803142	GGR,LEW 1, FT.UNION	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	0804142	GGR LWN 1 AL A+AL B	15.0,3.50	5	5	5	5	5	5	5	3	2	2	1	0	0	0	0	0	0	0	0	0	43
6	0805142	GGR LWN 1 AL A+E,R,B	15.0,3.50	3	2	3	2	3	10	9	7	5	3	1	0	0	0	0	0	0	0	0	0	48
7	0806142	GGR LWN 1 AL B+E,R,B	15.0,3.50	5	5	5	5	5	10	9	7	5	3	2	0	0	0	0	0	0	0	0	0	61
8	0807142	GGR LWN 1 LANCE+LEWS	15.0,3.50	5	5	5	5	5	10	9	7	5	3	1	0	0	0	0	0	0	0	0	0	60
9	0811142	GGR,S/WSH, LE 7000	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	0812142	GGR,S/WSH, LE 9000	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	0813142	GGR,S/WSH, MV 9000	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	0814142	GGR,S/WSH, MV 11000	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13	0815142	GGR,S/WSH,L7000M9000	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
14	0816142	GGR,S/WSH,M9000,11000	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15	0821142	GGRLWN 2+3, ALMD A	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
16	0823142	GGR,LEW2+3 E,R/S,B	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17	0824142	GGR,LEW2+3 FT UN	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
18	0826142	GGRLWN 2+3AL B+E,R,B	15.0,3.50	0	0	0	0	0	0	0	0	4	2	1	0	0	0	0	0	0	0	0	0	7
19	0827142	GGRLWN 2+3 LNCE+LEWS	15.0,3.50	0	0	0	0	0	0	0	3	4	3	1	0	0	0	0	0	0	0	0	0	11
20	0831142	GGRWASHAKI ALMOND	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
21	0832142	GGR,WASKIE LAN+LEW	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
22	0833142	GGR,WASKIE L.M.V	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
23	0834142	GGRWASHAKI LA,LE+AL	15.0,3.50	3	5	7	5	10	10	9	7	5	3	0	0	0	0	0	0	0	0	0	0	64
24	0835142	GGR,WASKIE AL+LMV	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
25	0841142	GGR,E/2,L4 M.VERDE	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
26	0842142	GGR,E/2 L4FT/UNION	15.0,3.50	1	1	1	1	1	5	3	3	3	2	1	0	0	0	0	0	0	0	0	0	24
27	0843142	GGR,E/2,L4 F/U +M.V	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
28	0851142	GGR,E/2,L4 F/UN +MV	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
29	1001142	U/NTA, WASATCH	15.0,3.50	3	4	6	8	8	8	7	6	4	2	0	0	0	0	0	0	0	0	0	0	56
30	1002142	U/NTA, BARREN	15.0,3.50	3	4	7	10	10	10	9	7	5	3	0	0	0	0	0	0	0	0	0	0	68
31	1003142	U/NTA, COALY	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
32	1004142	U/NTA, CASTLEGATE	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
33	1005142	U/NTA, COALY+CTLEGAT	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
34	1006142	U/NTA, WASTH+COALY	15.0,3.50	3	5	7	9	7	5	3	1	0	0	0	0	0	0	0	0	0	0	0	0	40
35	1007142	U/NTA, WASTH+BARREN	15.0,3.50	5	8	12	14	14	13	10	7	4	1	0	0	0	0	0	0	0	0	0	0	88
36	1101142	WINDRIVER, L F/UNION	15.0,3.50	10	12	20	25	25	19	18	14	10	6	2	0	0	0	0	0	0	0	0	0	161
37	1104142	W.RIVER , M.V.15000	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
38	1106142	W/R ,LA14000+MV15000	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
39	1107142	W/RIV,FRNTR +MUDDY	15.0,3.50	3	3	5	6	5	4	3	2	0	0	0	0	0	0	0	0	0	0	0	0	31
40	1301142	PICEANCE, CDR CUZET	15.0,3.50	2	2	2	2	2	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	12
41	1302142	PICEANCE, FT UNION	15.0,3.50	2	2	2	2	2	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	12
42	1303142	PICEANCE, MV 8000	15.0,3.50	2	2	2	2	2	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	12
43	1304142	PICEANCE, CDRCOZ+M.V	15.0,3.50	2	2	2	2	2	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	12
44	1305142	PICEANCE, F/UN +MIV	15.0,3.50	2	2	2	2	2	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	12
45	1306142	PICEANCE, F/UN,CRCZT	15.0,3.50	2	2	2	2	2	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	12
46	1307142	PICEANCE, L/CRT+JURA	15.0,3.50	2	2	2	2	2	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	12
47	2001142	DENVER MUDDY J	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
48	0502242	DENVER,B	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

TABLE E-4(1)b

49	0801242	GGR LEWINI ALMOND A	15.0,3.50	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	13
50	0802242	GGR,LEW 1, E,R,S,B	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
51	0803242	GGR,LEW 1, FT.UNION	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
52	0804242	GGR LEWINI AL A+AL B	15.0,3.50	0	0	0	0	0	0	0	0	0	2	3	3	4	5	5	5	5	5	5	5	5	5	4	56
53	0805242	GGR LEWINIAL A+E,R,B	15.0,3.50	0	0	0	0	0	0	0	1	3	5	7	9	15	15	15	15	15	15	15	15	15	14	159
54	0806242	GGR LEWINIAL B+C,R,B	15.0,3.50	0	0	0	0	0	0	0	1	3	5	7	13	15	15	15	15	15	15	15	15	15	15	164
55	0807242	GGR LEWINILNCE+LEWS	15.0,3.50	0	0	0	0	0	0	0	1	3	5	7	9	10	10	10	10	10	10	10	10	10	10	115
56	0811242	GGR S/WASH LEWS 7000	15.0,3.50	0	0	0	0	0	0	0	1	5	5	10	10	10	10	10	10	10	10	10	10	10	10	121
57	0812242	GGR S/WASH LEWS 9000	15.0,3.50	0	0	0	0	0	0	0	0	0	1	2	5	5	5	5	5	5	5	5	5	5	5	53
58	0813242	GGR,S/WSH, MV 9000	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
59	0814242	GGR,S/WSH, MV 11000	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
60	0815242	GGR S/W LE7000+MV9000	15.0,3.50	0	0	0	0	0	0	0	0	0	0	1	0	4	5	5	5	5	5	5	5	5	5	5	51
61	0816242	GGR,S/WSH,M9000,11007	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
62	0821242	GGR LEW2+3 ALMD A	15.0,3.50	0	0	0	0	0	0	0	0	0	0	2	2	5	10	10	10	10	10	10	10	10	10	10	99
63	0823242	GGR,LEW2+3 E,R/S,B	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
64	0824242	GGR LEW2+3 FT UNION	15.0,3.50	0	0	0	0	0	0	0	0	0	0	1	1	4	5	10	10	10	10	10	10	10	10	10	91
65	0826242	GGR LEW2+3ALB+E,R,B	15.0,3.50	0	0	0	0	0	0	0	0	0	0	3	5	9	10	10	10	10	10	10	10	10	10	10	107
66	0827242	GGR LEW2+3LNCE+LEWIS	15.0,3.50	0	0	0	0	0	0	0	0	0	0	3	7	9	10	10	10	10	10	10	10	10	10	10	109
67	0831242	GGR WASHAK ALMOND	15.0,3.50	0	0	0	0	0	0	0	0	0	0	2	2	2	2	2	2	2	2	2	2	2	2	2	24
68	0832242	GGR,WASKIE LAN+LEW	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
69	0833242	GGR,WASKIE L.M.V	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
70	0834242	GGR WASHAKLN,LE+ALMD	15.0,3.50	0	0	0	0	0	0	0	0	0	1	3	5	7	4	0	0	0	0	0	0	0	0	0	20
71	0835242	GGR WASHAKALMD+LMVDE	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	3	7	10	10	10	10	10	10	10	10	90
72	0841242	GGR,E/2,L4 M.VERDE	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
73	0842242	GGR E/2+LEA FT UNION	15.0,3.50	0	0	0	0	0	0	0	0	0	0	2	2	3	9	10	0	10	10	10	10	10	10	10	96
74	0843242	GGR,E/2,L4 F/U +M.V	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
75	0851242	GGR,E,L5,W/2L4,FT/UN	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
76	1001242	U/NTA ,WASATCH	15.0,3.50	0	0	0	0	0	0	0	0	1	2	4	6	6	7	7	5	5	5	5	8	10	10	81
77	1002242	U/NTA ,BARREN	15.0,3.50	0	0	0	0	0	0	0	0	1	3	5	7	5	5	5	5	5	5	5	5	5	5	65
78	1003242	U/NTA ,COALY	15.0,3.50	0	0	1	1	1	2	2	2	3	3	3	3	3	3	3	4	4	4	3	3	1	1	44
79	1004242	U/NTA ,CASTLEGATE	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	30
80	1005242	U/NTA ,COALY+CTLEGTE	15.0,3.50	0	0	1	2	2	3	3	3	3	3	5	5	5	5	5	5	5	5	5	5	5	5	68
81	1006242	U/NTA ,WASTCH+ COALY	15.0,3.50	0	0	0	1	3	5	7	9	10	10	10	10	10	10	10	10	10	7	5	3	0	0	130
82	1007242	U/NTA ,WASTCH+ BAREN	15.0,3.50	0	0	0	0	0	1	4	7	10	9	7	7	7	7	7	7	7	7	7	7	7	7	95
83	1101242	WIND RIV, L F/UNION	15.0,3.50	0	0	0	0	0	0	2	6	10	14	18	20	20	20	20	20	20	20	20	20	20	20	230
84	1104242	W.RIVER , M.V.15000	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
85	1106242	W/R ,LA14000+MV15000	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
86	1107242	W/RIV,FRNTR +MUDDY	15.0,3.50	0	0	0	0	1	2	3	4	5	7	7	7	7	7	7	7	7	7	7	4	3	0	92
87	1301242	PICEANCE, CJR COZ	15.0,3.50	0	0	0	0	0	0	0	1	3	4	4	10	10	10	10	10	10	10	10	10	10	10	112
88	1302242	PICEANCE, FT UNION	15.0,3.50	0	0	0	0	0	0	0	1	3	4	4	10	10	10	10	10	10	10	10	10	10	10	112
89	1303242	PICEANCE, M.V 8000	15.0,3.50	0	0	0	0	0	0	0	1	3	4	4	16	16	16	16	16	16	16	16	16	16	16	172
90	1304242	PICEANCE, CRCZT+M.V	15.0,3.50	0	0	0	0	0	0	0	1	3	4	4	10	10	10	10	10	10	10	10	10	10	10	112
91	1305242	PICEANCE, FLUN+ M.V	15.0,3.50	0	0	0	0	0	0	0	1	3	4	4	10	10	10	10	10	10	10	10	10	10	10	112
92	1306242	PICEANCE, F/UN+CRCZT	15.0,3.50	0	0	0	0	0	0	0	1	3	4	4	4	4	4	4	4	4	4	4	4	4	4	52
93	1307242	PICEANCE, L/CRET+JUR	15.0,3.50	0	0	0	0	0	0	0	1	3	4	4	10	10	10	10	10	10	10	10	10	10	10	112
94	2001242	DENVER MUDDY J	15.0,3.50	0	0	0	0	0	0	0	0	0	5	10	10	15	15	20	20	20	20	20	20	20	20	195
95	2422142	GGR,LEN2+3, AL 8	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
96	2425142	GGR,LEN2+3,AL A+B	15.0,3.50	0	1	1	2	2	3	3	3	2	1	0	0	0	0	0	0	0	0	0	0	0	0	0	15
97	2452142	GGR,B,L5,W/2L4,L+MV	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
98	2453142	GGR,B,L5,W/2L4, FRTR	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
99	2454142	GGR,B,L5,W/2L4MV,L+F	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
100	2455142	GGR,B,L5,W/2L4FU,MV,L	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
101	2502142	WIND R. LANCE 9000	15.0,3.50	0	0	0	0	0	0	0	1	1	3	3	2	1	0	0	0	0	0	0	0	0	0	0	11	0
102	2503142	W.RIVER , LAN 14000	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
103	2505142	WIND R. LFU +LN9000	15.0,3.50	1	4	5	7	7	7	6	5	4	3	2	0	0	0	0	0	0	0	0	0	0	0	0	51	0
104	2422242	GGR,LEN2+3, AL 8	15.0,3.50	0	0	0	0	0	0	0	1	2	1	1	1	1	2	2	2	2	2	2	2	2	2	2	22	0
105	2425242	GGR,LEN2+3,AL A+B	15.0,3.50	0	0	0	0	0	0	0	0	1	2	3	4	5	10	10	10	10	10	10	10	10	10	10	106	0
106	2452242	GGR,B,L5,W/2L4,L+MV	15.0,3.50	0	0	0	0	0	0	0	0	1	0	1	2	3	0	5	0	0	0	0	0	0	0	0	0	0
107	2453242	GGR,W/2L4,B,L5,FRNTR	15.0,3.50	0	0	0	0	0	0	0	0	0	1	2	3	5	5	7	7	9	9	9	11	11	11	11	100	0
108	2454242	GGR,W/2L4,B,L5,MVL+F	15.0,3.50	0	0	0	0	0	0	0	0	0	1	2	2	2	2	2	2	2	2	2	2	2	2	2	27	0
109	2455242	GGR,W/2L4,B,L5,T,MV	15.0,3.50	0	0	0	0	0	0	0	0	0	0	1	0	2	0	0	0	0	0	0	0	0	0	0	0	0
110	2502242	WIND R. LANCE 9000	15.0,3.50	0	0	0	0	0	0	0	0	0	0	1	2	3	4	5	5	5	5	5	5	5	5	5	55	0
111	2503242	W.RIVER , LAN 14000	15.0,3.50	0	0	0	0	0	0	0	0	0	1	0	2	3	0	4	0	5	0	7	0	7	0	7	0	0
112	2505242	WIND R. LFU +LN9000	15.0,3.50	0	0	0	0	0	0	0	1	2	3	4	5	7	7	7	7	7	7	7	7	7	7	7	78	0

TABLE E-4(1)c

SUMMARY OF WELL REQUIREMENTS

	CASE	LOCATION OF PROSPECT		NO. PROSP.	WILDCAT WELLS			W/C SUCCESS RATIO	DEVELOPMENT WELLS			TOTAL ALL WELLS
					PROD.	DRY	TOTAL		PROD.	DRY	TOTAL	
1	0502142	DENVER,B	15.0,3.50	0	0	0	0	I	0	0	0	0
2	0801142	GGR LWN 1 ALMOND A	15.0,3.50	7	4	2	6	.60	29	7	36	42
3	0802142	GGR,LEW 1, E,R,S,B	15.0,3.50	0	0	0	0	I	0	0	0	0
4	0803142	GGR,LEW 1, FT.UNION	15.0,3.50	0	0	0	0	I	0	0	0	0
5	0804142	GGR LWN 1 AL A+AL B	15.0,3.50	43	32	10	42	.76	101	25	126	168
6	0805142	GGR LWN 1 AL A+E,R,B	15.0,3.50	48	20	27	47	.43	31	7	38	85
7	0806142	GGR LWN 1 AL B+E,R,B	15.0,3.50	61	20	40	60	.33	55	13	68	128
8	0807142	GGR LWN 1 LANCE+LEWS	15.0,3.50	60	12	47	59	.21	118	29	147	206
9	0811142	GGR,S/WSH, LE 7000	15.0,3.50	0	0	0	0	I	0	0	0	0
10	0812142	GGR,S/WSH, LE 9000	15.0,3.50	0	0	0	0	I	0	0	0	0
11	0813142	GGR,S/WSH, MV 9000	15.0,3.50	0	0	0	0	I	0	0	0	0
12	0814142	GGR,S/WSH, MV 11000	15.0,3.50	0	0	0	0	I	0	0	0	0
13	0815142	GGR,S/WSH,L7000M9000	15.0,3.50	0	0	0	0	I	0	0	0	0
14	0816142	GGR,S/WSH,M9000,11000	15.0,3.50	0	0	0	0	I	0	0	0	0
15	0821142	GGRLWN 2+3, ALMD A	15.0,3.50	0	0	0	0	.38	0	0	0	0
16	0823142	GGR,LEW2+3 E,R/S,B	15.0,3.50	0	0	0	0	I	0	0	0	0
17	0824142	GGR,LEW2+3 FT UN	15.0,3.50	0	0	0	0	I	0	0	0	0
18	0826142	GGRLWN 2+3AL B+E,R,B	15.0,3.50	7	2	4	6	.40	8	2	10	16
19	0827142	GGRLWN 2+3 LNCE+LEWS	15.0,3.50	11	2	8	10	.21	29	7	36	46
20	0831142	GGRWASHAKI ALMOND	15.0,3.50	0	0	0	0	.36	0	0	0	0
21	0832142	GGR,WASKIE LAN+LEW	15.0,3.50	0	0	0	0	I	0	0	0	0
22	0833142	GGR,WASKIE L,M,V	15.0,3.50	0	0	0	0	I	0	0	0	0
23	0834142	GGRWASHAKI LA,LE+AL	15.0,3.50	64	37	27	64	.57	68	17	85	149
24	0835142	GGR,WASKIE AL+LMV	15.0,3.50	0	0	0	0	I	0	0	0	0
25	0841142	GGR,E/2,L4 M.VERDE	15.0,3.50	0	0	0	0	I	0	0	0	0
26	0842142	GGR,E/2 L4FT/UNION	15.0,3.50	24	0	0	0	I	0	0	0	0
27	0843142	GGR,E/2,L4 F/U +M.V	15.0,3.50	0	0	0	0	I	0	0	0	0
28	0851142	GGR,E,L5,W/2L4,FT/UN	15.0,3.50	0	0	0	0	I	0	0	0	0
29	1001142	U/NTA, WASATCH	15.0,3.50	56	23	32	55	.42	135	33	168	223
30	1002142	U/NTA, BARREN	15.0,3.50	68	28	38	66	.43	140	35	175	241
31	1003142	U/NTA, COALY	15.0,3.50	0	0	0	0	.48	0	0	0	0
32	1004142	U/NTA, CASTLEGATE	15.0,3.50	0	0	0	0	.26	0	0	0	0
33	1005142	U/NTA, COALY+CTLEGAT	15.0,3.50	0	0	0	0	.45	0	0	0	0
34	1006142	U/NTA, WASTH+COALY	15.0,3.50	40	21	18	39	.55	43	10	53	92
35	1007142	U/NTA, WASTH+BARREN	15.0,3.50	88	37	47	84	.44	117	29	146	230
36	1101142	WINDRIVER, L F/UNION	15.0,3.50	161	94	66	160	.59	852	213	1065	1225
37	1104142	W.RIVER , M.V.15000	15.0,3.50	0	0	0	0	I	0	0	0	0
38	1106142	W/R ,LA14000+MV15000	15.0,3.50	0	0	0	0	I	0	0	0	0
39	1107142	W/RIV,FRNTR +MUDDY	15.0,3.50	31	9	21	30	.32	163	40	203	233
40	1301142	PICEANCE, CUR COZET	15.0,3.50	12	4	7	11	.41	29	7	36	47
41	1302142	PICEANCE, FT UNION	15.0,3.50	12	3	8	11	.31	44	11	55	66
42	1303142	PICEANCE, MV 8000	15.0,3.50	12	3	8	11	.33	59	14	73	84
43	1304142	PICEANCE, CURCOZ+M.V	15.0,3.50	12	6	5	11	.56	23	5	28	39
44	1305142	PICEANCE, F/UN +MIV	15.0,3.50	12	5	6	11	.47	16	4	20	31
45	1306142	PICEANCE, F/UN,CRCZT	15.0,3.50	12	6	5	11	.52	24	6	30	41
46	1307142	PICEANCE, L/CRT+JURA	15.0,3.50	12	1	10	11	.17	38	9	47	58
47	2001142	DENVER MUDDY J	15.0,3.50	0	0	0	0	I	0	0	0	0
48	0502242	DENVER,B	15.0,3.50	0	0	0	0	I	0	0	0	0
49	0801242	GGR LEWINI ALMOND A	15.0,3.50	13	9	3	12	.71	27	6	33	45
50	0802242	GGR,LEW 1, E,R,S,B	15.0,3.50	0	0	0	0	I	0	0	0	0

TABLE E-4(1)d

51	0803242	GGR,LEW 1, FT.UNION	15.0,3.50	0	0	0	0	1	0	0	0	0	
52	0804242	GGR LEWINI AL A+AL B	15.0,3.50	56	43	13	56	.76	57	14	71	127	
53	0805242	GGR LEWINIAL A+E,R,B	15.0,3.50	159	96	62	158	.61	56	14	70	228	
54	0806242	GGR LEWINIAL B+C,R,B	15.0,3.50	164	53	110	163	.33	329	82	411	574	
55	0807242	GGR LEWINILNCE+LEWS	15.0,3.50	115	22	92	114	.20	208	52	260	374	
56	0811242	GGR S/WASH LEWS 7000	15.0,3.50	121	53	67	120	.44	83	20	103	223	
57	0812242	GGR S/WASH LEWS 9000	15.0,3.50	53	21	31	52	.41	43	10	53	105	
58	0813242	GGR,S/WSH, MV 9000	15.0,3.50	0	0	0	0	1	0	0	0	0	
59	0814242	GGR,S/WSH, MV 11000	15.0,3.50	0	0	0	0	1	0	0	0	0	
60	0815242	GGR S/W LE7000+MV9000	15.0,3.50	51	17	33	50	.35	34	8	42	92	
61	0816242	GGR,S/WSH,MV9000,11007	15.0,3.50	0	0	0	0	1	0	0	0	0	
62	0821242	GGR LEW2+3 ALMD A	15.0,3.50	99	68	38	106	.64	99	24	123	229	
63	0823242	GGR,LEW2+3 E,R/S,B	15.0,3.50	0	0	0	0	1	0	0	0	0	
64	0824242	GGR LEW2+3 FT UNION	15.0,3.50	91	30	60	90	.33	111	27	138	228	
65	0826242	GGR LEW2+3ALB+E,R,B	15.0,3.50	107	42	64	106	.40	245	61	306	412	
66	0827242	GGR LEW2+3LNCE+LEWIS	15.0,3.50	109	21	87	108	.20	278	69	347	455	
67	0831242	GGR WASHAK ALMOND	15.0,3.50	24	16	7	23	.68	14	3	17	40	
68	0832242	GGR,WASKIE LAN+LEW	15.0,3.50	0	0	0	0	1	0	0	0	0	
69	0833242	GGR,WASKIE L.M.V	15.0,3.50	0	0	0	0	1	0	0	0	0	
70	0834242	GGR WASHAKLN,LE+ALMD	15.0,3.50	20	13	6	19	.66	11	2	13	32	
71	0835242	GGR WASHAKALMD+LMVDE	15.0,3.50	90	41	41	82	.50	41	10	51	133	
72	0841242	GGR,E/2,L4 M.VERDE	15.0,3.50	0	0	0	0	1	0	0	0	0	
73	0842242	GGR E/2+LEA FT UNION	15.0,3.50	96	23	71	94	.25	265	66	331	425	
74	0843242	GGR,E/2,L4 F/U +M.V	15.0,3.50	0	0	0	0	1	0	0	0	0	
75	0851242	GGR,B,L5,W/2L4,FT/UN	15.0,3.50	0	0	0	0	1	0	0	0	0	
76	1001242	U/NTA ,WASATCH	15.0,3.50	81	34	46	80	.42	153	38	191	271	
77	1002242	U/NTA ,BARREN	15.0,3.50	66	28	37	65	.43	112	28	140	205	
78	1003242	U/NTA ,COALY	15.0,3.50	44	23	20	43	.54	80	20	100	143	
79	1004242	U/NTA ,CASTLEGATE	15.0,3.50	30	11	18	29	.39	77	19	95	125	
80	1005242	U/NTA ,COALY+CTLEGTE	15.0,3.50	68	30	37	67	.45	29	7	36	103	
81	1006242	U/NTA ,WASTCH+ COALY	15.0,3.50	130	71	58	129	.55	55	13	68	197	
82	1007242	U/NTA ,WASTCH+ BAREN	15.0,3.50	95	40	54	94	.43	121	30	151	245	
83	1101242	WIND RIV, L F/UNION	15.0,3.50	230	135	94	229	.59	976	244	1220	1449	
84	1104242	W.RIVER , M.V.15000	15.0,3.50	0	0	0	0	1	0	0	0	0	
85	1105242	W/R ,LA14000+MV15000	15.0,3.50	0	0	0	0	1	0	0	0	0	
86	1107242	W/RIV,FRNTR +MUDDY	15.0,3.50	92	34	57	91	.38	354	88	442	533	
87	1301242	PICEANCE, COR COZ	15.0,3.50	112	56	55	111	.51	147	36	183	294	
88	1302242	PICEANCE, FT UNION	15.0,3.50	112	14	97	111	.13	161	40	201	312	
89	1303242	PICEANCE, M.V 8000	15.0,3.50	172	55	116	171	.32	1033	258	1291	1462	
90	1304242	PICEANCE, CRCZT+M.V	15.0,3.50	112	72	39	111	.65	180	45	225	336	
91	1305242	PICEANCE, FLUN+ M.V	15.0,3.50	112	53	58	111	.48	328	82	410	521	
92	1306242	PICEANCE, F/UN+CRCZT	15.0,3.50	52	27	24	51	.52	63	15	78	129	
93	1307242	PICEANCE, L/CRET+JUR	15.0,3.50	112	18	93	111	.17	257	64	321	432	
94	2001242	DENVER MUDDY J	15.0,3.50	195	69	141	210	.33	334	83	417	627	
95	2422142	GGR,LEN2+3, AL B	15.0,3.50	0	0	0	0	1	0	0	0	0	
96	2425142	GGR,LEN2+3,AL A+B	15.0,3.50	15	9	5	14	.65	52	13	65	79	
97	2452142	GGR,B,L5,W/2L4,L+MV	15.0,3.50	0	0	0	0	1	0	0	0	0	
98	2453142	GGR,B,L5,W/2L4, FRTR	15.0,3.50	0	0	0	0	1	0	0	0	0	
99	2454142	GGR,B,L5,W/2L4MV,L+F	15.0,3.50	0	0	0	0	1	0	0	0	0	
100	2455142	GGR,B,L5,W/2L4FU,MV,L	15.0,3.50	0	0	0	0	1	0	0	0	0	
101	2502142	WIND R. LANCE 9000	15.0,3.50	11	6	4	10	.56	39	9	48	58	
102	2503142	W.RIVER , LAN 14000	15.0,3.50	0	0	0	0	1	0	0	0	0	
103	2505142	WIND R. LFU +LN9000	15.0,3.50	51	35	15	50	.69	121	30	151	201	
104	2422242	GGR,LEN2+3, AL B	15.0,3.50	22	5	16	21	.27	12	3	15	36	
105	2425242	GGR,LEN2+3,AL A+B	15.0,3.50	106	68	36	104	.65	165	41	206	310	
106	2452242	GGR,B,L5,W/2L4,L+MV	15.0,3.50	0	0	0	0	1	0	0	0	0	
107	2453242	GGR,W/2L4,B,L5,FRNTR	15.0,3.50	100	36	62	98	.37	171	42	213	311	
108	2454242	GGR,W/2L4,B,L5,MVL+F	15.0,3.50	27	10	16	26	.38	9	2	11	37	
109	2455242	GGR,W/2L4,B,L5,F,MV	15.0,3.50	0	0	0	0	1	0	0	0	0	
110	2502242	WIND R. LANCE 9000	15.0,3.50	33	21	33	54	.39	207	51	258	312	
111	2503242	W.RIVER , LAN 14000	15.0,3.50	0	0	0	0	1	0	0	0	0	
112	2505242	WIND R. LFU +LN9000	15.0,3.50	76	53	24	77	.69	301	75	376	453	

TABLE E-4(1)e

ANNUAL DRILLING SCHEDULE

	PROSPECT	YEAR	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
1	DENVER,B	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	GGR LWN 1 ALMOND A	15.0,3.50	6	6	6	6	6	6	6	6	0	0	0	0	0	0	0	0	0	0	0	0
3	GGR,LEW 1, E,R,S,B	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4	GGR,LEW 1, FT.UNION	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	GGR LWN 1 AL A+AL B	15.0,3.50	19	19	19	19	19	19	19	11	7	7	3	0	0	0	0	0	0	0	0	0
6	GGR LWN 1 AL A+E,R,B	15.0,3.50	5	3	5	1	5	18	16	12	9	5	1	0	0	0	0	0	0	0	0	0
7	GGR LWN 1 AL B+E,R,B	15.0,3.50	10	10	10	10	10	21	19	14	10	6	4	0	0	0	0	0	0	0	0	0
8	GGR LWN 1 LANCE+LEWS	15.0,3.50	17	17	17	17	17	34	31	24	17	10	3	0	0	0	0	0	0	0	0	0
9	GGR,S/WSH, LE 7000	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	GGR,S/WSH, LE 9000	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	GGR,S/WSH, MV 9000	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	GGR,S/WSH, MV 11000	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13	GGR,S/WSH,L7000M9000	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
14	GGR,S/WSH,M9000,11000	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15	GGRLWN 2+3, ALMD A	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
16	GGR,LEW2+3 E,R/S,B	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17	GGR,LEW2+3 FT UN	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
18	GGRLWN 2+3AL B+E,R,B	15.0,3.50	0	0	0	0	0	0	0	0	10	5	2	0	0	0	0	0	0	0	0	0
19	GGRLWN 2+3 LNCE+LEWS	15.0,3.50	0	0	0	0	0	0	0	13	17	13	4	0	0	0	0	0	0	0	0	0
20	GGRWASHAKI ALMOND	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
21	GGR,WASKIE LAN+LEW	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
22	GGR,WASKIE L.M.V	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
23	GGRWASHAKI LA,LE+AL	15.0,3.50	7	11	16	11	23	23	21	16	11	7	0	0	0	0	0	0	0	0	0	0
24	GGR,WASKIE AL+LMV	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
25	GGR,E/2,L4 M.VERDE	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
26	GGR,E/2 L4FT/UNION	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
27	GGR,E/2,L4 F/U +M.V.	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
28	GGR,B,L5,W/2L4,FT/UN	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
29	U/NTA, WASATCH	15.0,3.50	12	16	24	32	32	32	28	24	16	8	0	0	0	0	0	0	0	0	0	0
30	U/NTA, BARREN	15.0,3.50	10	14	25	35	35	35	32	25	17	10	0	0	0	0	0	0	0	0	0	0
31	U/NTA, COALY	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
32	U/NTA, CASTLEGATE	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
33	U/NTA, COALY+CTLEGAT	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
34	U/NTA, WASTH+COALY	15.0,3.50	7	11	16	21	16	11	7	2	0	0	0	0	0	0	0	0	0	0	0	0
35	U/NTA, WASTH+BARREN	15.0,3.50	13	21	31	37	37	34	26	18	10	2	0	0	0	0	0	0	0	0	0	0
36	WINDRIVER, L F/UNION	15.0,3.50	76	91	152	190	190	144	137	106	76	45	15	0	0	0	0	0	0	0	0	0
37	W.RIVER , M.V.15000	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
38	W/R ,LA14000+MV15000	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
39	W/RIV,FRNTR +MUDDY	15.0,3.50	22	22	38	45	38	30	22	15	0	0	0	0	0	0	0	0	0	0	0	0
40	PICEANCE, CCR COZET	15.0,3.50	8	8	8	8	8	4	4	0	0	0	0	0	0	0	0	0	0	0	0	0
41	PICEANCE, FT UNION	15.0,3.50	11	11	11	11	11	5	5	0	0	0	0	0	0	0	0	0	0	0	0	0
42	PICEANCE, MV 6000	15.0,3.50	14	14	14	14	14	7	7	0	0	0	0	0	0	0	0	0	0	0	0	0
43	PICEANCE, CURCOZ+M.V	15.0,3.50	6	6	6	6	6	3	3	0	0	0	0	0	0	0	0	0	0	0	0	0
44	PICEANCE, F/UN +MIV	15.0,3.50	5	5	5	5	5	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0
45	PICEANCE, F/UN,CRCZT	15.0,3.50	7	7	7	7	7	3	3	0	0	0	0	0	0	0	0	0	0	0	0	0
46	PICEANCE, L/CRT+JUKA	15.0,3.50	9	9	9	9	9	4	4	0	0	0	0	0	0	0	0	0	0	0	0	0
47	DENVER MUDDY J	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
48	DENVER,B	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
49	GGR LEWINI ALMOND A	15.0,3.50	0	0	0	0	0	0	0	3	3	3	3	3	3	3	3	3	3	3	3	3
50	GGR,LEW 1, E,R,S,B	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
51	GGR,LEW 1, FT.UNION	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
52	GGR LEWINI AL A+AL B	15.0,3.50	0	0	0	0	0	0	0	4	6	6	9	11	11	11	11	11	11	11	11	9
53	GGR LEWINIAL A+E,R,B	15.0,3.50	0	0	0	0	0	0	1	4	7	10	12	21	21	21	21	21	21	21	21	20

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54	GGR LEWINIAL B+C,R,B	15.0,3.50	0	0	0	0	0	0	3	10	17	24	45	52	52	52	52	52	52	52	52	52
55	GGR LEWINILNCE+LEWS	15.0,3.50	0	0	0	0	0	0	3	9	16	22	29	32	32	32	32	32	32	32	32	32
56	GGR S/WASH LEWS 7000	15.0,3.50	0	0	0	0	0	0	1	9	9	18	18	18	18	18	18	18	18	18	18	18
57	GGR S/WASH LEWS 9000	15.0,3.50	0	0	0	0	0	0	0	0	2	4	10	10	10	10	10	10	10	10	10	10
58	GGR,S/WSH, MV 9000	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
59	GGR,S/WSH, MV 11000	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
60	GGR S/W LE7000+MV9000	15.0,3.50	0	0	0	0	0	0	0	0	1	1	7	9	9	9	9	9	9	9	9	9
61	GGR,S/WSH,MV9000,11000	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
62	GGR LEW2+3 ALMJ A	15.0,3.50	0	0	0	0	0	0	0	0	4	4	11	22	22	22	22	22	22	22	22	22
63	GGR,LEW2+3 E,R/S,B	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
64	GGR LEW2+3 FT UNION	15.0,3.50	0	0	0	0	0	0	0	0	2	2	10	12	25	25	25	25	25	25	25	25
65	GGR LEW2+3ALB+E,R,B	15.0,3.50	0	0	0	0	0	0	0	0	11	19	34	38	38	38	38	38	38	38	38	38
66	GGR LEW2+3LNCE+LEWIS	15.0,3.50	0	0	0	0	0	0	0	0	12	29	37	41	41	41	41	41	41	41	41	41
67	GGR WASHAK ALMJND	15.0,3.50	0	0	0	0	0	0	0	0	3	3	3	3	3	3	3	3	3	3	3	3
68	GGR,WASKIE LAN+LEW	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
69	GGR,WASKIE L.M.V	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
70	GGR WASHAKLN,LE+ALMD	15.0,3.50	0	0	0	0	0	0	1	5	8	11	6	0	0	0	0	0	0	0	0	0
71	GGR WASHAKALMD+LMVDE	15.0,3.50	0	0	0	0	0	0	0	0	0	0	4	10	15	15	15	15	15	15	15	15
72	GGR,E/2,L4 M.VERDE	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
73	GGR E/2+LEA FT UNION	15.0,3.50	0	0	0	0	0	0	0	8	8	13	40	44	0	44	44	44	44	44	44	44
74	GGR,E/2,L4 F/U +M.V	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
75	GGR,B,L5,W/2L4,FT/UN	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
76	U/NTA ,WASATCH	15.0,3.50	0	0	0	0	0	0	3	6	13	20	20	23	23	16	16	16	16	26	33	33
77	U/NTA ,BARREN	15.0,3.50	0	0	0	0	0	0	3	9	15	21	15	15	15	15	15	15	15	15	15	15
78	U/NTA ,CDALY	15.0,3.50	0	0	3	3	3	6	6	6	9	9	9	9	9	13	13	13	9	9	3	3
79	U/NTA ,CASTLEGATE	15.0,3.50	0	0	0	0	0	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
80	U/NTA ,CDALY+CTLEGTE	15.0,3.50	0	0	1	3	3	4	4	4	4	4	4	7	7	7	7	7	7	7	7	7
81	U/NTA ,WASTCH+ CDALY	15.0,3.50	0	0	0	1	4	7	10	13	15	15	15	15	15	15	15	15	15	10	7	4
82	U/NTA ,WASTCH+ BAKEN	15.0,3.50	0	0	0	0	0	2	2	10	18	26	23	18	18	18	18	18	18	18	18	18
83	WIND RIV, L F/UNION	15.0,3.50	0	0	0	0	0	0	12	37	63	88	113	126	126	126	126	126	126	126	126	126
84	W.RIVER , M.V.15000	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
85	W/R ,LA14000+MV15000	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
86	W/RIV,FRNTR +MUDDY	15.0,3.50	0	0	0	5	11	17	23	29	40	40	40	40	40	40	40	40	40	23	17	11
87	PICEANCE, CDR CDZ	15.0,3.50	0	0	0	0	0	0	2	7	10	10	26	26	26	26	26	26	26	26	26	26
88	PICEANCE, FT UNION	15.0,3.50	0	0	0	0	0	2	8	11	11	27	27	27	27	27	27	27	27	27	27	27
89	PICEANCE, M.V 8000	15.0,3.50	0	0	0	0	0	8	25	34	34	136	136	136	136	136	136	136	136	136	136	136
90	PICEANCE, CRCZT+M.V	15.0,3.50	0	0	0	0	0	3	9	12	12	30	30	30	30	30	30	30	30	30	30	30
91	PICEANCE, FLUN+ M.V	15.0,3.50	0	0	0	0	0	4	14	18	18	46	46	46	46	46	46	46	46	46	46	46
92	PICEANCE, F/UN+CRCZT	15.0,3.50	0	0	0	0	0	2	7	10	10	10	10	10	10	10	10	10	10	10	10	10
93	PICEANCE, L/CRET+JUR	15.0,3.50	0	0	0	0	0	3	11	15	15	38	38	38	38	38	38	38	38	38	38	38
94	DENVER MUDDY J	15.0,3.50	0	0	0	0	0	0	0	0	16	32	32	48	48	64	64	64	64	64	64	64
95	GGR,LEN2+3, AL B	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
96	GGR,LEN2+3,AL A+B	15.0,3.50	0	5	5	10	10	16	16	10	5	0	0	0	0	0	0	0	0	0	0	0
97	GGR,B,L5,W/2L4,L+MV	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
98	GGR,B,L5,W/2L4, FRTR	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
99	GGR,B,L5,W/2L4MV,L+F	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
100	GGR,B,L5,W/2L4FJ,MV,L	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
101	WIND R. LANCE 9000	15.0,3.50	0	0	0	0	0	5	5	16	16	10	5	0	0	0	0	0	0	0	0	0
102	W.RIVER , LAN 14000	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
103	WIND R. LFU +LN9000	15.0,3.50	3	15	19	26	26	26	22	19	15	11	7	0	0	0	0	0	0	0	0	0
104	GGR,LEN2+3, AL B	15.0,3.50	0	0	0	0	0	0	0	1	1	1	1	3	3	3	3	3	3	3	3	3
105	GGR,LEN2+3,AL A+B	15.0,3.50	0	0	0	0	0	2	2	5	8	11	14	29	29	29	29	29	29	29	29	29
106	GGR,B,L5,W/2L4,L+MV	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
107	GGR,W/2L4,B,L5,FRNTR	15.0,3.50	0	0	0	0	0	0	3	3	9	15	15	22	22	28	28	28	34	34	34	34
108	GGR,W/2L4,B,L5,MVL+F	15.0,3.50	0	0	0	0	0	0	1	2	2	2	2	2	2	2	2	2	2	2	2	2
109	GGR,W/2L4,B,L5,T,MV	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
110	WIND R. LANCE 9000	15.0,3.50	0	0	0	0	0	0	0	5	11	17	22	28	28	28	28	28	28	28	28	28
111	W.RIVER , LAN 14000	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
112	WIND R. LFU +LN9000	15.0,3.50	0	0	0	0	0	0	5	11	17	23	29	40	40	40	40	40	40	40	40	40
	TOTAL WELLS IN EACH YEAR		267	321	447	534	545	528	550	607	704	750	997	1072	1046	1109	1109	1109	1111	1116	1097	1085

TABLE E-4(1)g

INVESTMENT REQUIREMENTS AND RESERVE ADDITIONS

YEAR	INVESTMENT (MM$)	GAS RESERVES ADDED (BCF)	CUMMULATIVE GAS RESERVES
1	255.8	468.2	468.2
2	314.7	599.7	1067.9
3	422.9	835.9	1903.8
4	493.1	1004.0	2907.8
5	519.4	1048.3	3956.1
6	565.2	1107.9	5063.9
7	624.3	1197.0	6260.9
8	731.8	1367.5	7628.4
9	903.0	1631.6	9260.0
10	985.8	1750.3	11010.3
11	1360.5	2262.5	13272.9
12	1489.5	2493.2	15766.1
13	1570.2	2488.3	18254.4
14	1551.5	2585.3	20839.8
15	1551.5	2585.3	23425.1
16	1551.5	2585.3	26010.4
17	1558.8	2597.1	28607.5
18	1564.4	2582.7	31190.2
19	1547.2	2517.5	33707.7
20	1531.6	2466.2	36173.9
	20997.6 TOTAL INVESTMENT		

TABLE E-4(1)h

CASH FLOW AND PRODUCTION SUMMARY

YEAR	ANNUAL CASH FLOW (MM$)	CUMUL. CASH FLOW (MM$)	ANNUAL NGL PRODN (MMB)	CUMUL. NGL PRODN (MMB)	ANNUAL GAS PRODN (BCF)	CUMUL. GAS PRODN (BCF)	ANNUAL GAS PRODN (BCF EQ1)	CUMUL. GAS PRODN (BCF EQ1)
1	-.8435	-.8435	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2	-12.1552	-12.9987	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
3	-54.2053	-67.2039	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
4	-41.9769	-109.1809	.5260	.5260	25.1733	25.1733	28.2243	28.2243
5	-36.4030	-145.5838	1.4791	2.0051	71.1708	96.3442	79.7493	107.9736
6	40.4558	-105.1280	2.9252	4.9303	143.3774	239.7215	160.3435	268.3171
7	129.4855	24.3575	4.4783	9.4086	225.8666	465.5882	251.8408	520.1579
8	220.0837	244.4412	6.1274	15.5360	312.0584	777.6466	347.5973	867.7553
9	324.8653	569.3065	7.8208	23.3568	397.6673	1175.3139	443.0280	1310.7832
10	411.6403	980.9468	9.3425	32.6993	472.9285	1648.2423	527.1151	1837.8983
11	477.9569	1458.9038	10.9230	43.6223	550.0722	2198.3146	613.4257	2451.3240
12	556.6410	2015.5447	12.7776	56.3999	638.8020	2837.1166	712.9123	3164.2363
13	616.4620	2632.0067	14.6981	71.0980	731.3501	3568.4667	816.5989	3980.8351
14	709.8803	3341.8950	17.0139	88.1119	839.0255	4407.4922	937.7061	4918.5412
15	840.4261	4182.3211	19.7721	107.8840	962.3412	5369.8334	1077.0192	5995.5605
16	988.3388	5170.6600	22.5310	130.4150	1086.1482	6455.9816	1216.8281	7212.3886
17	1157.5824	6328.3423	25.0604	155.4754	1202.5234	7658.5050	1347.8740	8560.2625
18	1310.0063	7638.3487	27.2556	182.8311	1309.2723	8967.7772	1467.9349	10028.1975
19	1458.3712	9096.9198	29.4949	212.3260	1408.7434	10376.5207	1579.8141	11608.0115
20	1599.7734	10696.6932	31.4600	243.7860	1501.4628	11877.9834	1683.9308	13291.9423
21	1737.2167	12433.9119	33.2540	277.0401	1585.7509	13463.7343	1778.6244	15070.5667
22	1913.1035	14347.0154	34.6712	311.9112	1661.4963	15125.2307	1863.7490	16934.3157
23	2288.2552	16635.2707	36.2765	348.1877	1728.3132	16853.5438	1938.7169	18873.0325
24	2299.6827	18934.9534	34.2849	382.4727	1642.9204	18496.4642	1841.7731	20714.8056
25	2263.8192	21198.7726	31.4509	413.9236	1516.4147	20012.8789	1698.8300	22413.6356
26	2096.3852	23295.1578	28.1674	442.0909	1366.7706	21379.6495	1530.1414	23943.7770
27	1914.6266	25209.9844	25.3065	467.3975	1235.5918	22615.2413	1382.3697	25326.1467
28	1747.5107	26957.4951	22.9601	490.3576	1127.2265	23742.4678	1260.3950	26586.5417
29	1608.1742	28565.6693	21.0311	511.3886	1036.9321	24779.3999	1158.9123	27745.4540
30	1485.2899	30050.9592	19.3579	530.7465	957.6937	25737.0936	1069.9694	28815.4234
31	1372.6669	31423.6261	17.8695	548.6160	886.5630	26623.6566	990.2061	29805.6295
32	1269.6060	32693.2321	16.5461	565.1621	822.8377	27446.4943	918.8049	30724.4343
33	1176.1944	33869.4265	15.3795	580.5415	766.3163	28212.8127	855.5192	31579.9535
34	1092.1642	34961.5907	14.3479	594.8894	716.8759	28928.6886	799.2835	32379.2370
35	1016.2764	35977.8672	13.4235	608.3129	670.8726	29599.7612	748.7291	33127.9761
36	947.2261	36925.0933	12.5797	620.8926	629.5238	30229.2850	702.4662	33830.4423
37	884.9416	37809.1349	11.8075	632.7003	591.6191	30820.9041	660.4134	34490.8557
38	828.7871	38637.9221	11.0927	643.7929	556.5277	31377.4318	620.9650	35111.4207
39	771.3245	39409.2465	10.4218	654.2147	523.4737	31900.9055	583.8200	35695.3507
40	721.5067	40127.7533	9.7883	664.0030	492.3778	32393.2832	548.9724	36244.2235
41	674.2041	40801.9574	9.1854	673.1884	462.1248	32855.4081	515.4901	36759.6236
42	628.3919	41430.3493	8.6028	681.7915	432.9270	33288.0538	482.8230	37242.4465
43	584.3225	42014.3717	8.0420	689.8335	404.4692	33692.5230	451.1130	37693.5595
44	540.7002	42555.1600	7.4977	697.3312	376.5627	34069.0877	420.0493	38113.6088
45	499.5235	43054.6834	6.9822	704.3134	349.7496	34418.8373	390.2464	38503.8552
46	459.5266	43514.2100	6.4837	710.7972	323.6361	34742.4734	361.2418	38865.0970
47	420.4220	43934.6320	5.9977	716.7949	297.9988	35040.4722	332.7854	39197.8824
48	382.5736	44317.2057	5.5318	722.3267	273.0461	35313.5183	305.1305	39503.0129
49	346.5049	44663.7106	5.0866	727.4132	249.1964	35562.7147	278.6984	39781.7113
50	311.9021	44975.6127	4.6590	732.0722	226.2348	35788.9495	253.2568	40034.9681
51	276.8377	45252.4504	4.2121	736.2842	202.3391	35991.2887	226.7691	40261.7373
52	244.9582	45497.4086	3.7960	740.0802	180.3804	36171.6691	202.3971	40464.1344
53	214.9973	45712.4058	3.3972	743.4775	159.4120	36331.0811	179.1160	40643.2504
54	186.9368	45899.3426	3.0160	746.4935	139.5420	36470.6232	157.0464	40800.2969
55	160.3020	46059.6246	2.6521	749.1475	120.8668	36591.4900	136.2489	40936.5457
56	136.3391	46196.2637	2.3009	751.4485	103.6993	36695.1893	117.0447	41053.5905
57	114.7870	46311.0507	1.9785	753.4270	88.3493	36783.5386	99.8249	41153.4153
58	97.0256	46408.0763	1.7022	755.1292	75.5207	36859.0593	85.3936	41238.8089
59	81.8635	46489.9397	1.4585	756.5878	64.4159	36923.4752	72.8754	41311.6843
60	69.0419	46559.0016	1.2467	757.8344	54.8643	36978.3395	62.0949	41373.7792
61	57.4613	46616.4629	1.0536	758.8881	46.1863	37024.5258	52.2974	41426.0766
62	47.6038	46664.0667	.8834	759.7715	38.7054	37063.2312	43.8292	41469.9058
63	38.5850	46702.7516	.7282	760.4996	31.8176	37095.0488	36.0409	41505.9467
64	30.4836	46733.2353	.5802	761.0798	25.4085	37120.4572	28.7735	41534.7203
65	23.1509	46756.3862	.4458	761.5256	19.5947	37140.0519	22.1801	41556.9004
66	17.0526	46773.4388	.3315	761.8571	14.6090	37154.6609	16.5319	41573.4322
67	11.8419	46785.2807	.2322	762.0893	10.2580	37164.9189	11.6048	41585.0370
68	7.1984	46792.4791	.1431	762.2324	6.3092	37171.2281	7.1392	41592.1762
69	3.3737	46795.8528	.0669	762.2993	2.9534	37174.1816	3.3413	41595.5176

37174. BCF--MAX GAS PRODUCED IN SCENARIO

TABLE E-4(1)i

ECONUMIC SUMMARY

PROFIT INDICATORS

DISCOUNTED PRESENT WORTH AT 15.0 PCT. (MM$)	2117.03086
DCF RATE OF RETURN (PERCENT)	61.70
PAYOUT TIME (YEARS)	5.81
PROFIT PER INVESTMENT ($/$)	2.229
MAX. UNRECOVERED INVESTMENT (MM$)	145.5838
NET CASH RECOVERY AFTER TAX (MM$)	46795.8528
EXPLORATION EXPENDITURE (MM$)	7479.1428
PRODUCTION INVESTMENT (MM$)	14069.4050
TOTAL INVESTMENT (MM$)	20997.5855
OPERATING EXPENSE (MM$)	7001.9493

TABLE E-4(2)a

Standard Scenario at $3.50 and 15%
Base and Advanced Technologies--Western U.S.

CASE 6.31 SCENARIO 1 08/13/80 20 YEAR DEVELOPMENT PROGRAM

	YEAR OF DEVELOPMENT			1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	
	LOCATION OF PROSPECTS--																							
1	1101142	WESTERN INTERMED	15.0,3.50	5	5	6	6	10	13	19	20	20	20	0	0	0	0	0	0	0	0	0	0	124
2	1107142	WESTERN SHALLOW	15.0,3.50	15	15	15	15	17	19	23	25	25	25	0	0	0	0	0	0	0	0	0	0	194
3	1301142	WESTERN INTERMED	15.0,3.50	9	9	9	9	10	11	8	8	8	8	0	0	0	0	0	0	0	0	0	0	89
4	1302142	WESTERN INTERMED	15.0,3.50	5	5	5	5	5	6	6	6	5	4	0	0	0	0	0	0	0	0	0	0	52
5	1303142	WESTERN INTERMED	15.0,3.50	5	5	5	5	6	7	7	8	8	8	0	0	0	0	0	0	0	0	0	0	64
6	1307142	WESTERN INTERMED	15.0,3.50	13	13	13	13	13	16	12	12	12	12	0	0	0	0	0	0	0	0	0	0	129
7	1101242	WESTERN INTERMED	15.0,3.50	0	1	1	1	1	2	3	1	0	0	0	0	0	0	0	0	0	0	0	0	10
8	1107242	WESTERN SHALLOW	15.0,3.50	0	1	1	1	1	2	3	1	0	0	0	0	0	0	0	0	0	0	0	0	10
9	1301242	WESTERN INTERMED	15.0,3.50	0	0	0	0	3	3	4	3	3	3	7	8	9	10	10	10	10	10	10	10	113
10	1302242	WESTERN INTERMED	15.0,3.50	0	0	0	0	18	18	18	18	20	20	10	10	10	10	10	10	10	10	10	10	212
11	1303242	WESTERN INTERMED	15.0,3.50	0	0	0	0	2	6	9	10	10	12	10	10	10	10	10	10	10	10	10	10	149
12	1307242	WESTERN INTERMED	15.0,3.50	0	0	0	0	0	1	2	3	5	6	8	8	8	8	9	9	9	9	9	9	103
13	2502142	WESTERN DEEP	15.0,3.50	0	0	0	0	0	0	1	2	2	2	5	7	7	7	7	7	7	7	7	7	75
14	2503142	WESTERN DEEP	15.0,3.50	0	0	0	0	6	7	11	14	25	25	20	20	20	17	17	17	17	17	17	17	264
15	2502242	WESTERN DEEP	15.0,3.50	0	0	0	0	0	2	2	4	5	5	5	5	5	5	5	5	5	5	5	5	68
16	2503242	WESTERN DEEP	15.0,3.50	0	0	0	0	0	2	2	4	6	6	6	6	6	6	6	6	6	6	6	6	80

TABLE E-4(2)b

SUMMARY OF WELL REQUIREMENTS

	CASE	LOCATION OF PROSPECT		NO. PROSP.	WILDCAT WELLS PROD.	WILDCAT WELLS DRY	WILDCAT WELLS TOTAL	W/C SUCCESS RATIO	DEVELOPMENT WELLS PROD.	DEVELOPMENT WELLS DRY	DEVELOPMENT WELLS TOTAL	TOTAL ALL WELLS
1	1101142	WESTERN INTERMED	15.0,3.50	124	73	50	123	.59	656	164	820	943
2	1107142	WESTERN SHALLOW	15.0,3.50	194	61	132	193	.32	1075	256	1201	1474
3	1301142	WESTERN INTERMED	15.0,3.50	89	36	52	88	.41	216	54	270	358
4	1302142	WESTERN INTERMED	15.0,3.50	52	15	36	51	.31	191	47	238	289
5	1303142	WESTERN INTERMED	15.0,3.50	64	20	43	63	.33	316	79	395	458
6	1307142	WESTERN INTERMED	15.0,3.50	129	21	107	128	.17	409	102	511	639
7	1101242	WESTERN INTERMED	15.0,3.50	10	5	4	9	.59	42	10	52	61
8	1107242	WESTERN SHALLOW	15.0,3.50	10	3	6	9	.38	38	9	47	56
9	1301242	WESTERN INTERMED	15.0,3.50	113	57	55	112	.51	148	37	185	297
10	1302242	WESTERN INTERMED	15.0,3.50	212	27	184	211	.13	304	76	380	591
11	1303242	WESTERN INTERMED	15.0,3.50	149	48	100	148	.32	895	223	1118	1266
12	1307242	WESTERN INTERMED	15.0,3.50	103	17	85	102	.17	236	59	295	397
13	2502142	WESTERN DEEP	15.0,3.50	75	41	33	74	.56	267	66	333	407
14	2503142	WESTERN DEEP	15.0,3.50	284	0	0	0	1	0	0	0	0
15	2502242	WESTERN DEEP	15.0,3.50	68	26	41	67	.39	256	64	320	387
16	2503242	WESTERN DEEP	15.0,3.50	80	0	0	0	1	0	0	0	0

TABLE E-4(2)c

ANNUAL DRILLING SCHEDULE

	PROSPECT	YEAR	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
1	WESTERN INTERMED	15.0,3.50	38	38	45	45	76	99	144	152	152	152	0	0	0	0	0	0	0	0	0	0
2	WESTERN SHALLOW	15.0,3.50	114	114	114	114	129	144	175	190	190	190	0	0	0	0	0	0	0	0	0	0
3	WESTERN INTERMED	15.0,3.50	36	36	36	36	40	44	32	32	32	32	0	0	0	0	0	0	0	0	0	0
4	WESTERN INTERMED	15.0,3.50	27	27	27	27	27	33	33	33	27	22	0	0	0	0	0	0	0	0	0	0
5	WESTERN INTERMED	15.0,3.50	35	35	35	35	43	50	50	57	57	57	0	0	0	0	0	0	0	0	0	0
6	WESTERN INTERMED	15.0,3.50	64	64	64	64	64	79	59	59	59	59	0	0	0	0	0	0	0	0	0	0
7	WESTERN INTERMED	15.0,3.50	0	6	6	6	6	12	18	6	0	0	0	0	0	0	0	0	0	0	0	0
8	WESTERN SHALLOW	15.0,3.50	0	5	5	5	5	11	17	5	0	0	0	0	0	0	0	0	0	0	0	0
9	WESTERN INTERMED	15.0,3.50	0	0	0	0	7	7	10	7	7	7	18	21	23	26	26	26	26	26	26	26
10	WESTERN INTERMED	15.0,3.50	0	0	0	0	50	50	50	50	55	55	27	27	27	27	27	27	27	27	27	27
11	WESTERN INTERMED	15.0,3.50	0	0	0	0	17	51	76	85	85	102	85	85	85	85	85	85	85	85	85	85
12	WESTERN INTERMED	15.0,3.50	0	0	0	0	0	3	7	11	19	23	30	30	30	30	34	34	34	34	34	34
13	WESTERN DEEP	15.0,3.50	0	0	0	0	0	0	5	10	10	10	27	38	38	38	38	38	38	38	38	38
14	WESTERN DEEP	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15	WESTERN DEEP	15.0,3.50	0	0	0	0	0	11	11	22	28	28	28	28	28	28	28	28	28	28	28	28
16	WESTERN DEEP	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	TOTAL WELLS IN EACH YEAR		314	325	332	332	464	594	687	719	721	737	215	229	231	234	238	238	238	238	238	238

TABLE E-4(2)d

INVESTMENT REQUIREMENTS AND RESERVE ADDITIONS

YEAR	INVESTMENT (MM$)	GAS RESERVES ADDED (BCF)	CUMMULATIVE GAS RESERVES
1	173.2	276.1	276.1
2	181.8	292.3	568.5
3	187.6	301.1	869.6
4	198.6	301.1	1170.7
5	301.5	455.8	1626.5
6	434.0	627.0	2253.5
7	516.5	755.9	3009.4
8	578.8	792.3	3801.7
9	594.2	793.2	4594.9
10	608.3	826.2	5421.2
11	303.9	335.9	5757.0
12	317.6	353.6	6110.6
13	314.2	359.8	6470.4
14	316.2	365.9	6836.3
15	319.5	368.6	7204.9
16	319.5	368.6	7573.6
17	319.5	368.6	7942.2
18	319.5	368.6	8310.8
19	319.5	368.6	8679.5
20	319.5	368.6	9048.1
	6943.4	TOTAL INVESTMENT	

TABLE E-4(2)e

CASH FLOW AND PRODUCTION SUMMARY

YEAR	ANNUAL CASH FLOW (MM$)	CUMUL. CASH FLOW (MM$)	ANNUAL NGL PRODN (MMB)	CUMUL. NGL PRODN (MMB)	ANNUAL GAS PRODN (BCF)	CUMUL. GAS PRODN (BCF)	ANNUAL GAS PRODN (BCF EQI)	CUMUL. GAS PRODN (BCF EQI)
1	-.6772	-.6772	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2	-9.4469	-10.1241	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
3	-25.6949	-35.7290	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
4	-27.2060	-62.9349	.1224	.1224	6.6762	6.6762	7.3861	7.3861
5	-36.6757	-99.6106	.4291	.5515	23.4806	30.1568	25.9696	33.3558
6	-24.4555	-124.0661	.8736	1.4252	48.1236	78.2804	53.1906	86.5464
7	-16.2233	-140.2894	1.2879	2.7131	70.7721	149.0525	78.2420	164.7883
8	-5.2482	-145.5377	1.7149	4.4280	94.6122	243.6647	104.5586	269.3469
9	2.0500	-143.4876	2.2916	6.7196	126.1134	369.7781	139.4048	408.7518
10	21.3422	-122.1455	3.1180	9.8376	170.2066	539.9847	188.2909	597.0426
11	67.5436	-54.6018	4.1111	13.9487	221.4323	761.4169	245.2765	842.3192
12	151.7461	97.1443	5.1282	19.0768	273.0266	1034.4436	302.7720	1145.0911
13	239.6248	336.7691	6.0325	25.1094	319.2428	1353.6864	354.2314	1499.3207
14	292.8548	629.6239	6.5753	31.6846	348.5910	1702.2774	386.7276	1886.0483
15	355.9320	985.5559	6.6793	38.3639	356.6968	2059.0742	395.4365	2281.4848
16	356.8300	1342.3859	6.4181	44.7820	347.2726	2406.3468	384.4975	2665.9823
17	352.2337	1694.6196	6.2107	50.9927	349.7342	2756.0810	376.7561	3042.7384
18	347.4115	2042.2312	6.0882	57.0808	338.2738	3085.3548	373.5853	3416.3237
19	347.7185	2389.9496	6.0399	63.1207	339.2307	3424.4854	374.2620	3790.5857
20	350.5505	2740.5002	6.0210	69.1417	341.3051	3765.7905	376.2266	4166.8125
21	354.1861	3094.6863	6.0076	75.1493	343.4183	4109.2088	378.2624	4545.0748
22	370.3872	3465.0734	6.0004	81.1497	345.6348	4454.8437	380.4372	4925.5120
23	427.9461	3893.0196	6.0005	87.1502	348.0422	4802.8858	382.8449	5308.3569
24	440.2556	4333.3052	5.7315	92.8817	334.8563	5137.7421	368.0991	5676.4560
25	433.6522	4766.9573	5.2861	98.1678	311.5253	5449.2675	342.1646	6018.6206
26	405.1021	5172.0594	4.7996	102.9674	284.2741	5733.5415	312.1118	6330.7324
27	371.1877	5543.2471	4.3615	107.3288	259.1045	5993.6460	285.4009	6616.1333
28	340.5787	5883.8258	3.9976	111.3264	240.0197	6233.6657	263.2057	6879.3390
29	314.3986	6198.2244	3.6869	115.0134	222.9216	6456.4873	244.2056	7123.5648
30	291.3885	6489.6130	3.4088	118.4222	207.3534	6663.8407	227.1244	7350.6893
31	269.7973	6759.4103	3.1557	121.5779	193.1759	6857.0166	211.4789	7562.1682
32	249.9212	7009.3315	2.9270	124.5049	180.3331	7037.3497	197.3098	7759.4780
33	231.6199	7240.9514	2.7221	127.2270	168.6975	7206.0473	184.4859	7943.9638
34	214.8726	7455.8240	2.5389	129.7659	158.1547	7364.2020	172.9605	8116.8443
35	199.1377	7655.0117	2.3714	132.1373	148.3951	7512.5971	162.1490	8278.9933
36	184.6142	7839.6259	2.2191	134.3564	139.2001	7651.7971	152.0709	8431.0642
37	171.1140	8010.7399	2.0775	136.4339	130.7171	7782.5144	142.8158	8573.8801
38	158.8596	8169.5996	1.9619	138.4008	123.0752	7905.5896	134.4544	8708.3345
39	147.6642	8317.2638	1.8546	140.2555	116.0070	8021.5966	126.7639	8835.0984
40	137.5752	8454.8390	1.7572	142.0127	109.4310	8131.0277	119.6227	8954.7211
41	128.0268	8582.8658	1.6635	143.6761	103.1152	8234.1429	112.7033	9067.4245
42	119.0067	8701.8725	1.5762	145.2524	97.0769	8331.2197	106.2190	9173.7034
43	110.6151	8812.4876	1.4959	146.7483	91.3730	8422.6127	100.0493	9273.7527
44	102.8686	8915.4562	1.4233	148.1716	86.1103	8508.7231	94.3654	9368.1182
45	96.2570	9011.7132	1.3611	149.5327	81.4238	8590.1469	89.3163	9457.4345
46	90.1864	9101.8997	1.3038	150.8365	77.1682	8667.3151	84.7301	9542.1646
47	84.3276	9186.1913	1.2479	152.0843	73.0748	8740.3899	80.3125	9622.4770
48	78.6138	9264.8051	1.1920	153.2763	69.0144	8809.4043	75.9280	9698.4050
49	73.2726	9338.0777	1.1353	154.4117	65.1686	8874.5728	71.7534	9770.1604
50	68.1708	9406.2485	1.0795	155.4912	61.4389	8936.0117	67.7001	9837.8605
51	62.0216	9468.2702	1.0046	156.4957	56.4195	8992.4312	62.2459	9900.1065
52	56.6759	9524.9461	.9350	157.4307	51.9223	9044.3535	57.3450	9957.4515
53	51.7299	9576.6760	.8687	158.2993	47.7242	9092.0777	52.7624	10010.2139
54	46.9696	9623.6456	.8034	159.1028	43.6308	9135.7085	48.2908	10058.5046
55	41.8480	9665.5436	.7306	159.8334	39.1874	9174.8959	43.4251	10101.9297
56	36.4965	9702.0401	.6484	160.4819	34.3066	9209.2025	38.0676	10139.9973
57	30.9379	9732.9780	.5578	161.0396	29.2153	9238.4178	32.4503	10172.4476
58	25.3226	9758.3006	.4632	161.5028	24.0651	9262.4829	26.6914	10199.1390
59	20.0465	9778.3471	.3712	161.8740	19.0158	9281.4987	21.1687	10220.3077
60	15.1163	9793.4635	.2828	162.1568	14.2852	9295.7840	15.9255	10236.2333
61	12.8517	9806.3152	.2449	162.4017	12.3126	9308.0966	13.7332	10249.9665
62	10.5821	9816.8973	.2060	162.6077	10.3111	9318.3477	11.5056	10261.4722
63	8.4137	9825.3110	.1663	162.7740	8.3825	9326.7302	5.3566	10270.8307
64	6.4035	9831.7145	.1328	162.9067	6.5781	9333.3083	7.3482	10278.1790
65	4.6762	9836.3911	.1011	163.0099	4.9740	9338.2823	5.5605	10283.7395
66	3.3212	9839.7122	.0745	163.0844	3.6371	9341.9194	4.0693	10287.8086
67	2.1777	9841.8899	.0512	163.1355	2.4793	9344.3987	2.7760	10290.5848
68	1.2199	9843.1099	.0306	163.1661	1.4667	9345.8655	1.6441	10292.2289
69	.5678	9843.6777	.0143	163.1804	.6818	9346.5472	.7647	10292.9936

9347. BCF--MAX GAS PRODUCED IN SCENARIO

TABLE E-4(2)f

ECONOMIC SUMMARY

PROFIT INDICATORS

DISCOUNTED PRESENT WORTH AT 15.0 PCT. (MM$)	404.00525
DCF RATE OF RETURN (PERCENT)	32.70
PAYOUT TIME (YEARS)	10.36
PROFIT PER INVESTMENT ($/$)	1.418
MAX. UNRECOVERED INVESTMENT (MM$)	145.5377
NET CASH RECOVERY AFTER TAX (MM$)	9843.6777
EXPLORATION EXPENDITURE (MM$)	2217.9137
PRODUCTION INVESTMENT (MM$)	4876.1329
TOTAL INVESTMENT (MM$)	6943.3932
OPERATING EXPENSE (MM$)	3263.3441

TABLE E-4(3)a

Standard Scenario at $3.50 and 15%
Base and Advanced Technologies--Southwest U.S.

CASE 1.31 SCENARIO 1 08/12/80 20 YEAR DEVELOPMENT PROGRAM

	YEAR OF DEVELOPMENT			1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	
	LOCATION OF PROSPECTS--																							
1	1601142	SAN JUAN DAKOTA	15., 3.50	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	7
2	1801142	VAL VERDE SONORA	15., 3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	1601242	SAN JUAN DAKOTA	15., 3.50	0	0	0	0	0	1	4	6	6	6	6	6	6	6	6	6	6	6	6	6	83
4	1801242	VAL VERDE SONORA	15., 3.50	0	0	0	0	0	1	2	3	3	5	5	5	5	5	5	5	5	5	3	2	59
5	2101142	COTTON VALLEY TREND	15., 3.50	10	14	21	21	20	15	5	0	0	0	0	0	0	0	0	0	0	0	0	0	106
6	2201142	EDWARDS LIME SW	15., 3.50	2	4	6	8	10	5	2	0	0	0	0	0	0	0	0	0	0	0	0	0	37
7	2202142	EDWARDS LIME CENTRAL	15., 3.50	0	0	0	1	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	3
8	2301142	VAL VERDE OZONA	15., 3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	2101242	COTTON VALLEY TREND	15., 3.50	0	1	2	9	20	35	45	50	45	40	35	35	30	25	20	20	20	20	20	20	492
10	2201242	EDWARDS LIME SW	15., 3.50	0	0	0	0	0	10	10	12	12	12	12	12	12	12	12	12	12	12	12	12	176
11	2202242	EDWARDS LIME CENTRAL	15., 3.50	0	0	0	0	0	0	1	2	3	5	10	15	20	30	30	30	30	30	30	30	266
12	2301242	VAL VERDE OZONA	15., 3.50	0	0	0	0	0	1	1	2	2	2	2	2	2	2	2	2	2	2	2	1	27

TABLE E-4(3)b

SUMMARY OF WELL REQUIREMENTS

	CASE	LOCATION OF PROSPECT		NO. PROSP.	WILDCAT WELLS PROD.	WILDCAT WELLS DRY	WILDCAT WELLS TOTAL	W/C SUCCESS RATIO	DEVELOPMENT WELLS PROD.	DEVELOPMENT WELLS DRY	DEVELOPMENT WELLS TOTAL	TOTAL ALL WELLS
1	1601142	SAN JUAN DAKOTA	15., 3.50	7	1	6	7	.15	39	9	48	55
2	1801142	VAL VERDE SONORA	15., 3.50	0	0	0	0	1	0	0	0	0
3	1601242	SAN JUAN DAKOTA	15., 3.50	83	46	49	95	.49	682	170	852	947
4	1801242	VAL VERDE SONORA	15., 3.50	59	23	56	79	.29	769	192	961	1040
5	2101142	COTTON VALLEY TREND	15., 3.50	106	27	93	120	.23	334	83	417	537
6	2201142	EDWARDS LIME SW	15., 3.50	37	13	39	52	.26	45	11	56	108
7	2202142	EDWARDS LIME CENTRAL	15., 3.50	3	1	3	4	.26	3	0	3	7
8	2301142	VAL VERDE OZONA	15., 3.50	0	0	0	0	1	0	0	0	0
9	2101242	COTTON VALLEY TREND	15., 3.50	492	167	393	560	.30	799	199	998	1558
10	2201242	EDWARDS LIME SW	15., 3.50	176	100	152	252	.40	207	51	258	510
11	2202242	EDWARDS LIME CENTRAL	15., 3.50	266	46	244	290	.16	188	47	235	525
12	2301242	VAL VERDE OZONA	15., 3.50	27	9	30	39	.24	69	17	86	125

TABLE E-4(3)c

ANNUAL DRILLING SCHEDULE

	PROSPECT		YEAR	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
1	SAN JUAN DAKOTA	15.,	3.50	8	8	8	8	8	8	8	0	0	0	0	0	0	0	0	0	0	0	0	0
2	VAL VERDE SONORA	15.,	3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	SAN JUAN DAKOTA	15.,	3.50	0	0	0	0	0	11	45	68	68	68	68	68	68	68	68	68	68	68	68	68
4	VAL VERDE SONORA	15.,	3.50	0	0	0	0	0	17	35	52	52	88	88	88	88	88	88	88	88	88	52	35
5	COTTON VALLEY TREND	15.,	3.50	50	71	106	106	101	76	25	0	0	0	0	0	0	0	0	0	0	0	0	0
6	EDWARDS LIME SW	15.,	3.50	5	11	17	23	29	14	5	0	0	0	0	0	0	0	0	0	0	0	0	0
7	EDWARDS LIME CENTRAL	15.,	3.50	0	0	0	2	0	2	0	2	0	0	0	0	0	0	0	0	0	0	0	0
8	VAL VERDE OZONA	15.,	3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	COTTON VALLEY TREND	15.,	3.50	0	3	6	28	63	111	142	158	142	126	111	111	95	79	63	63	63	63	63	63
10	EDWARDS LIME SW	15.,	3.50	0	0	0	0	0	29	29	35	35	35	35	35	35	35	35	35	35	35	35	35
11	EDWARDS LIME CENTRAL	15.,	3.50	0	0	0	0	0	0	2	4	6	11	23	34	46	69	69	69	69	69	69	69
12	VAL VERDE OZONA	15.,	3.50	0	0	0	0	0	14	14	28	28	28	28	28	28	28	28	28	28	28	28	14
	TOTAL WELLS IN EACH YEAR			63	93	137	167	201	282	305	347	331	356	353	364	360	367	351	351	351	351	315	284

TABLE E-4(3)d

INVESTMENT REQUIREMENTS AND RESERVE ADDITIONS

YEAR	INVESTMENT ($MM)	GAS RESERVES ADDED (BCF)	CUMULATIVE GAS RESERVES
1	55.0	132.7	132.7
2	84.8	209.3	342.1
3	127.8	318.1	660.1
4	174.8	442.8	1102.9
5	221.8	593.2	1696.1
6	334.4	914.9	2611.0
7	361.2	993.8	3604.8
8	411.3	1110.5	4715.3
9	390.1	1052.4	5767.7
10	405.1	1065.2	6832.9
11	426.5	1092.6	7925.5
12	471.1	1188.2	9113.8
13	492.5	1215.7	10329.4
14	556.4	1338.7	11668.1
15	535.3	1270.5	12938.6
16	535.3	1270.5	14209.1
17	535.3	1270.5	15479.6
18	535.3	1270.5	16750.1
19	514.9	1227.8	17977.8
20	497.0	1192.7	19170.6
	7667.7	TOTAL INVESTMENT	

TABLE E-4(3)e

CASH FLOW AND PRODUCTION SUMMARY

YEAR	ANNUAL CASH FLOW (MM$)	CUMUL. CASH FLOW (MM$)	ANNUAL NGL PRODN (MMB)	CUMUL. NGL PRODN (MMB)	ANNUAL GAS PRODN (BCF)	CUMUL. GAS PRODN (BCF)	ANNUAL GAS PRODN (BCF EQI)	CUMUL. GAS PRODN (BCF EQI)
1	-1.0930	-1.0930	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2	-4.1193	-5.2122	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
3	-14.1303	-19.3425	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
4	-22.4353	-42.2778	.0001	.0661	3.1885	3.1885	3.5721	3.5721
5	-28.7514	-71.0493	.2187	.2848	10.4868	13.6753	11.7552	15.3273
6	-33.4291	-104.4784	.4688	.7536	22.2991	35.9744	25.0179	40.3452
7	-26.3078	-130.7861	.8696	1.6232	40.8239	76.7982	45.8677	86.2129
8	-19.1501	-149.9362	1.4636	3.0868	66.7801	143.5783	75.2688	161.4817
9	30.3550	-119.5813	2.3191	5.4059	112.0246	255.6029	125.4755	286.9572
10	87.5246	-32.0567	3.2952	8.7011	162.2845	417.8874	181.3966	468.3538
11	164.1494	132.0927	4.3119	13.0130	217.1161	635.0035	242.1253	710.4791
12	237.6105	369.7032	5.2522	18.2652	269.9332	904.9366	300.3957	1010.8749
13	299.3564	669.0596	6.0960	24.3612	320.9954	1225.9320	356.3524	1367.2272
14	360.6137	1029.6733	6.8520	31.2132	374.5734	1600.5054	414.3150	1781.5422
15	427.6260	1457.2992	7.5609	38.7742	430.9004	2031.4058	474.7538	2256.2961
16	487.2921	1944.5913	8.2160	46.9901	490.7887	2522.1945	538.4412	2794.7373
17	583.6995	2528.2908	8.7540	55.7442	556.9174	3079.1119	607.6908	3402.4281
18	666.6181	3194.9090	9.1406	64.8849	613.1318	3692.2436	666.1482	4068.5763
19	742.6708	3937.5798	9.4623	74.3473	663.3554	4355.5990	718.2369	4786.8132
20	812.4848	4750.0646	9.7460	84.0932	708.9388	5064.5378	765.4654	5552.2786
21	880.9722	5631.0368	10.0033	94.0966	750.8330	5815.3708	808.8524	6361.1310
22	956.6739	6587.7106	10.2419	104.3385	789.5441	6604.9149	848.9471	7210.0782
23	1149.3591	7737.0697	10.4633	114.8017	825.4803	7430.3952	886.1672	8096.2453
24	1141.8368	8878.9065	10.1776	124.9793	784.3557	8214.7508	843.3855	8939.6308
25	1104.8405	9983.7471	9.7712	134.7505	738.9228	8953.6737	795.5957	9735.2265
26	1055.3295	11039.0766	9.3568	144.1073	695.9573	9649.6310	750.2385	10485.4649
27	999.3471	12038.4237	8.9223	153.0316	654.9292	10304.5602	706.6788	11192.1437
28	947.6687	12986.0924	8.5293	161.5610	619.4632	10924.0234	668.9334	11861.0771
29	901.5360	13887.7284	8.1597	169.7207	587.7074	11511.7308	635.0339	12496.1110
30	857.9402	14745.6686	7.8054	177.5261	558.2003	12069.9311	603.4718	13099.5828
31	816.9152	15562.5837	7.4705	184.9967	531.2655	12601.2167	574.6145	13674.1974
32	779.4876	16342.0713	7.1594	192.1561	507.5483	13108.7649	549.0727	14223.2702
33	744.3991	17086.4704	6.8718	199.0279	485.6982	13594.6631	525.7549	14749.0251
34	711.7269	17798.1974	6.6056	205.6336	465.8381	14060.5012	504.1509	15253.1759
35	680.8161	18479.0135	6.3537	211.9872	446.8426	14507.3438	483.6938	15736.8698
36	651.1387	19130.1522	6.1077	218.0949	428.5542	14935.8980	463.9787	16200.8484
37	621.9949	19752.1471	5.8544	223.9493	410.4660	15346.3640	444.4216	16645.2701
38	592.4428	20344.5899	5.5859	229.5352	391.9993	15738.3633	424.3973	17069.6674
39	561.8096	20906.1996	5.2970	234.8321	372.5869	16110.9502	403.3093	17472.9767
40	530.2260	21436.4255	4.9882	239.8204	352.2810	16463.2313	381.2128	17854.1895
41	497.0860	21933.5115	4.6548	244.4752	330.7820	16794.0132	357.7799	18211.9694
42	462.1033	22395.6148	4.2974	248.7726	308.0381	17102.0513	332.9628	18544.9323
43	425.4701	22821.0849	3.9167	252.6912	284.1786	17386.2299	306.9069	18851.8391
44	388.2331	23209.3180	3.5329	256.2242	259.8716	17646.1015	280.3626	19132.2017
45	351.4360	23560.7540	3.1521	259.3762	235.7912	17881.8927	254.0731	19386.2749
46	315.2348	23875.9888	2.7871	262.1633	211.9878	18093.8805	228.1529	19614.4277
47	280.5499	24156.5387	2.4479	264.6112	189.0645	18282.9451	203.2623	19817.6900
48	247.4551	24403.9938	2.1323	266.7435	167.1186	18450.0637	179.4869	19997.1761
49	216.6202	24620.6140	1.8399	268.5834	146.6049	18596.6686	157.2763	20154.4523
50	187.5715	24808.1855	1.5735	270.1569	127.1933	18723.8619	136.3199	20290.7722
51	159.2014	24967.3869	1.3176	271.4745	108.1309	18831.9929	115.7733	20406.5455
52	132.3147	25099.7017	1.0792	272.5537	89.9823	18921.9752	96.2414	20502.7869
53	106.4862	25206.1878	.8481	273.4019	72.4932	18994.4684	77.4122	20580.1991
54	82.2947	25288.4825	.6311	274.0329	56.0820	19050.5504	59.7424	20639.9415
55	60.7094	25349.1919	.4332	274.4661	41.4385	19091.9889	43.9509	20683.8924
56	43.8962	25393.0881	.2690	274.7351	30.0618	19122.0507	31.6222	20715.5146
57	31.3883	25424.4764	.1540	274.8892	21.5732	19143.6240	22.4665	20737.9811
58	23.6317	25448.1081	.0914	274.9805	16.2627	19159.8867	16.7926	20754.7737
59	18.6283	25466.7364	.0571	275.0376	12.8100	19172.6966	13.1411	20767.9148
60	15.5941	25482.3304	.0422	275.0798	10.7138	19183.4105	10.9586	20778.8734
61	13.4497	25495.7802	.0326	275.1124	9.2435	19192.6539	9.4327	20788.3061
62	11.7338	25507.5140	.0261	275.1385	8.0649	19200.7189	8.2161	20796.5221
63	10.1639	25517.6779	.0216	275.1601	6.9872	19207.7061	7.1125	20803.6347
64	8.4409	25526.1188	.0175	275.1776	5.8029	19213.5090	5.9045	20809.5391
65	6.8690	25532.9879	.0142	275.1918	4.7219	19218.2309	4.8041	20814.3432
66	5.3347	25538.3226	.0111	275.2028	3.6672	19221.8981	3.7314	20818.0746
67	3.9331	25542.2557	.0083	275.2111	2.7035	19224.6016	2.7516	20820.8262
68	2.5877	25544.8434	.0055	275.2167	1.7787	19226.3803	1.8108	20822.6370
69	1.2895	25546.1330	.0028	275.2195	.8864	19227.2667	.9025	823.5394

19227. BCF--MAX GAS PRODUCED IN [illegible]ARIO

TABLE E-4(3)f

ECONOMIC SUMMARY

PROFIT INDICATORS

DISCOUNTED PRESENT WORTH AT 15.0 PCT. (MM$)	882.15006
DCF RATE OF RETURN (PERCENT)	42.70
PAYOUT TIME (YEARS)	9.20
PROFIT PER INVESTMENT ($/$)	3.332
MAX. UNRECOVERED INVESTMENT (MM$)	149.9362
NET CASH RECOVERY AFTER TAX (MM$)	25546.1330
EXPLORATION EXPENDITURE (MM$)	3470.6016
PRODUCTION INVESTMENT (MM$)	4466.4892
TOTAL INVESTMENT (MM$)	7667.6852
OPERATING EXPENSE (MM$)	2335.5648

TABLE E-4(4)a

Standard Scenario at $3.50 and 15%
Base and Advanced Technologies--Other Southwest

20 YEAR DEVELOPMENT PROGRAM

	YEAR OF DEVELOPMENT / LOCATION OF PROSPECTS--			1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	
1	16C1142	NEW MEX-W TEX	15., 3.50	2	2	3	3	3	3	2	0	0	0	0	0	0	0	0	0	0	0	0	0	18
2	1801142	CENTRAL TEXAS	15., 3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	1601242	NEW MEX-W TEX	15., 3.50	0	0	0	1	2	7	18	30	45	45	45	45	45	45	45	45	45	45	45	45	598
4	1801242	CENTRAL TEXAS	15., 3.50	0	0	0	0	0	5	10	15	15	25	25	25	25	25	25	25	25	25	25	10	305
5	2101142	EAST TEX-LA	15., 3.50	2	4	5	6	5	5	5	0	0	0	0	0	0	0	0	0	0	0	0	0	32
6	2201142	TEXAS GULF SOUTH	15., 3.50	10	10	9	7	5	6	3	0	0	0	0	0	0	0	0	0	0	0	0	0	50
7	2202142	TEXAS GULF CENTRAL	15., 3.50	0	0	0	1	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	3
8	2301142	OKLAHOMA	15., 3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	2101242	EAST TEX-LA	15., 3.50	0	0	1	2	5	10	20	30	35	50	75	100	100	100	100	100	100	100	100	100	1128
10	2201242	TEXAS GULF SOUTH	15., 3.50	0	0	1	3	5	14	27	50	100	150	170	170	170	170	170	170	170	170	170	170	2056
11	2202242	TEXAS GULF CENTRAL	15., 3.50	0	0	0	0	0	0	0	0	0	10	20	30	40	50	60	60	60	60	60	60	510
12	2301242	OKLAHOMA	15., 3.50	0	0	0	0	0	4	4	8	8	8	8	8	8	8	8	8	8	8	6	4	108

TABLE E-4(4)b

SUMMARY OF WELL REQUIREMENTS

	CASE	LOCATION OF PROSPECT		NO. PROSP.	WILDCAT WELLS PROD.	WILDCAT WELLS DRY	WILDCAT WELLS TOTAL	W/C SUCCESS RATIO	DEVELOPMENT WELLS PROD.	DEVELOPMENT WELLS DRY	DEVELOPMENT WELLS TOTAL	TOTAL ALL WELLS
1	16C1142	NEW MEX-W TEX	15., 3.50	18	3	17	20	.15	102	25	127	147
2	1801142	CENTRAL TEXAS	15., 3.50	0	0	0	0	I	0	0	0	0
3	1601242	NEW MEX-W TEX	15., 3.50	598	337	357	694	.49	4920	1230	6150	6844
4	1801242	CENTRAL TEXAS	15., 3.50	305	118	294	412	.29	3975	993	4968	5380
5	2101142	EAST TEX-LA	15., 3.50	32	8	23	36	.23	100	25	125	161
6	2201142	TEXAS GULF SOUTH	15., 3.50	50	18	53	71	.26	62	15	77	148
7	2202142	TEXAS GULF CENTRAL	15., 3.50	3	1	3	4	.26	3	0	3	7
8	2301142	OKLAHOMA	15., 3.50	0	0	0	0	I	0	0	0	0
9	2101242	EAST TEX-LA	15., 3.50	1128	384	901	1285	.30	1834	458	2292	3577
10	2201242	TEXAS GULF SOUTH	15., 3.50	2050	1170	1775	2945	.40	2418	604	3022	5967
11	2202242	TEXAS GULF CENTRAL	15., 3.50	510	69	468	557	.16	360	90	450	1007
12	2301242	OKLAHOMA	15., 3.50	108	39	123	162	.24	276	69	345	507

TABLE E-4(4)c

ANNUAL DRILLING SCHEDULE

	PROSPECT		YEAR	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
1	NEW MEX-W TEX	15.,	3.50	16	16	24	24	24	24	16	0	0	0	0	0	0	0	0	0	0	0	0	0
2	CENTRAL TEXAS	15.,	3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	NEW MEX-W TEX	15.,	3.50	0	0	0	11	22	80	206	343	515	515	515	515	515	515	515	515	515	515	515	515
4	CENTRAL TEXAS	15.,	3.50	0	0	0	0	0	88	176	264	264	441	441	441	441	441	441	441	441	441	441	176
5	EAST TEX-LA	15.,	3.50	10	20	25	30	25	25	25	0	0	0	0	0	0	0	0	0	0	0	0	0
6	TEXAS GULF SOUTH	15.,	3.50	29	29	26	20	14	17	8	0	0	0	0	0	0	0	0	0	0	0	0	0
7	TEXAS GULF CENTRAL	15.,	3.50	0	0	0	2	0	2	0	2	0	0	0	0	0	0	0	0	0	0	0	0
8	OKLAHOMA	15.,	3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	EAST TEX-LA	15.,	3.50	0	0	3	6	15	31	63	99	111	158	237	317	317	317	317	317	317	317	317	317
10	TEXAS GULF SOUTH	15.,	3.50	0	0	2	8	14	40	78	145	291	437	495	495	495	495	495	495	495	495	495	495
11	TEXAS GULF CENTRAL	15.,	3.50	0	0	0	0	0	0	0	0	0	23	46	69	92	115	138	138	138	138	138	138
12	OKLAHOMA	15.,	3.50	0	0	0	0	0	57	57	114	114	114	114	114	114	114	114	114	114	114	114	57
	TOTAL WELLS IN EACH YEAR			55	65	80	101	114	364	629	963	1295	1688	1848	1951	1974	1997	2020	2020	2020	2020	2020	1698

TABLE E-4(4)d

INVESTMENT REQUIREMENTS AND RESERVE ADDITIONS

YEAR	INVESTMENT (MM$)	GAS RESERVES ADDED (BCF)	CUMULATIVE GAS RESERVES
1	53.6	133.6	133.6
2	62.4	155.0	288.6
3	76.2	190.8	479.4
4	102.9	252.3	731.7
5	115.9	301.6	1033.3
6	317.7	776.1	1809.5
7	547.3	1361.5	3171.0
8	655.7	2137.7	5308.7
9	1247.9	3244.1	8552.8
10	1765.1	4658.3	13211.1
11	2072.4	5512.2	18723.3
12	2277.0	6044.2	24767.5
13	2366.0	6235.4	31002.9
14	2455.0	6426.5	37429.4
15	2544.1	6617.7	44047.1
16	2544.1	6617.7	50664.8
17	2544.1	6617.7	57282.5
18	2544.1	6617.7	63900.2
19	2544.1	6617.7	70517.9
20	2360.3	6242.4	76760.2
	29395.9 TOTAL INVESTMENT		

TABLE E-4(4)e

CASH FLOW AND PRODUCTION SUMMARY

YEAR	ANNUAL CASH FLOW (MM$)	CUMUL. CASH FLOW (MM$)	ANNUAL NGL PRODN (MMB)	CUMUL. NGL PRODN (MMB)	ANNUAL GAS PRODN (BCF)	CUMUL. GAS PRODN (BCF)	ANNUAL GAS PRODN (BCF EQ1)	CUMUL. GAS PRODN (BCF EQ1)
1	-.4574	-.4574	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2	-3.1259	-3.5833	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
3	-15.7514	-19.3347	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
4	-16.5349	-35.8735	.0247	.0247	4.6553	4.6553	4.7986	4.7986
5	-14.9530	-50.8265	.0744	.0992	11.2867	15.9419	11.7164	16.5170
6	-12.7051	-63.5316	.1616	.2608	20.4748	36.4167	21.4121	37.9291
7	-7.3446	-70.8762	.2979	.5587	32.9991	69.4159	34.6881	72.5973
8	-25.0986	-95.9748	.4674	1.0261	48.4430	117.8579	51.1537	123.7510
9	-42.3378	-138.3126	.7907	1.8168	81.1981	199.0560	85.7844	209.5354
10	-63.7922	-202.1048	1.3714	3.1882	140.7668	339.7228	148.6607	358.1961
11	-80.8098	-282.9146	2.2471	5.4352	241.0957	580.8585	254.1286	612.3247
12	-41.0951	-324.0096	3.5727	8.9080	420.0257	1001.7841	441.6476	1053.9723
13	160.3562	-163.6534	5.4575	14.4555	691.1179	1692.9020	722.7715	1776.7438
14	484.7909	321.1374	7.9281	22.3835	1015.0773	2707.9794	1056.0691	2832.6038
15	874.1985	1195.3359	10.7744	33.1580	1338.0256	4041.0049	1400.5173	4233.3211
16	1307.3369	2502.6747	13.8972	47.0552	1675.1694	5716.1743	1755.7732	5989.0943
17	1733.5801	4236.2548	16.8791	63.9343	1999.3830	7715.5573	2097.2619	8086.3763
18	2186.1800	6422.4347	19.7632	83.6975	2315.2536	10030.8109	2429.8803	10516.2566
19	2613.8955	9036.3302	22.5041	106.2017	2608.6516	12639.4625	2739.1755	13255.4321
20	3025.3981	12064.7283	25.1111	131.3128	2882.0165	15521.4790	3027.6612	16283.0932
21	3431.0841	15495.8125	27.5843	158.8971	3136.5850	18656.0649	3296.5748	19579.6680
22	3876.2096	19372.0221	29.9205	188.8176	3374.4011	22032.4659	3547.9402	23127.6081
23	4776.9705	24148.9926	32.1023	220.9199	3596.6264	25629.0943	3782.8215	26910.4297
24	4830.9068	28979.8994	31.6564	252.5783	3432.5236	29061.6179	3616.1424	30526.5721
25	4714.1445	33694.0439	30.7297	283.3080	3241.7079	32303.3257	3419.9349	33946.5119
26	4504.9170	38196.9609	29.3288	312.6368	3036.0271	35339.3528	3206.1343	37152.6462
27	4249.1862	42448.1471	27.7798	340.4166	2840.4712	38179.8240	3001.5941	40154.2403
28	4013.0133	46461.1604	26.3963	366.8129	2673.8717	40853.6957	2826.9702	42981.2105
29	3804.1734	50265.3336	25.0855	391.8984	2525.3516	43379.0473	2670.6477	45652.0582
30	3607.7783	53873.1121	23.8215	415.7199	2389.3466	45768.3938	2527.5113	48179.5695
31	3422.2431	57295.3552	22.6227	438.3426	2264.6395	48033.0333	2395.8510	50575.4205
32	3249.3505	60544.7057	21.5240	459.8667	2153.7064	50186.7397	2278.6257	52854.0463
33	3091.7203	63636.4260	20.5442	480.4108	2054.9419	52241.7816	2174.0982	55028.1445
34	2944.2336	66580.6595	19.6739	500.0848	1963.2003	54204.9819	2077.3090	57105.4535
35	2805.6121	69386.2717	18.8882	518.9729	1877.0509	56082.0328	1986.6622	59092.0557
36	2674.5272	72060.7989	18.1629	537.1359	1795.2422	57877.2749	1900.3172	60992.6429
37	2551.9953	74612.7942	17.4849	554.6208	1718.2163	59595.4913	1819.0287	62812.2716
38	2433.6085	77046.4027	16.8315	571.4523	1643.3448	61238.8361	1740.0677	64553.2393
39	2317.7774	79364.2401	16.1959	587.6482	1569.4465	62808.2826	1663.3826	66216.6219
40	2206.9367	81571.1768	15.5635	603.2117	1498.9985	64307.2811	1588.2669	67802.8887
41	2095.1077	83666.2845	14.9220	618.1337	1421.5444	65725.8255	1506.0023	69310.9810
42	1981.0310	85647.3156	14.2689	632.4026	1345.2275	67071.0530	1427.9871	70738.9682
43	1860.8177	87508.1333	13.5698	645.9724	1264.4236	68335.4766	1343.1285	72082.0967
44	1734.8826	89243.0159	12.8223	658.7947	1179.4461	69514.9227	1253.8152	73335.9119
45	1602.9518	90845.9676	12.0284	670.8230	1094.9664	70609.8892	1164.7369	74500.6488
46	1477.3140	92330.2815	11.1626	681.9856	1005.9960	71614.9852	1069.6388	75570.2876
47	1341.2816	93671.5632	10.2321	692.2177	912.7080	72527.7042	972.1452	76542.4328
48	1190.4632	94871.0264	9.2147	701.4324	816.7301	73344.4442	870.1752	77412.6021
49	1056.5491	95927.5752	8.1356	709.5680	719.9073	74064.4015	767.0937	78179.6958
50	914.5961	96842.1713	7.0420	716.6100	623.6589	74688.0604	664.5625	78844.3983
51	774.2110	97616.3824	5.9961	722.5661	528.3479	75216.4083	562.8932	79407.2915
52	639.5955	98255.9778	4.9032	727.4693	436.8096	75653.2178	465.2483	79872.5398
53	511.9447	98767.9225	3.8062	731.2755	349.3034	76003.1212	372.0016	80245.5414
54	393.8316	99161.7541	2.9454	734.3110	269.4073	76272.5285	286.4908	80531.5321
55	290.7297	99452.4839	2.0828	736.3937	199.2536	76471.7821	211.3336	80742.8657
56	204.8598	99657.3436	1.3395	737.7332	140.8538	76612.6359	148.6227	80891.4884
57	136.4707	99793.8143	.7646	738.4978	94.2488	76706.8847	98.6635	80990.1519
58	92.5963	99886.4107	.4206	738.9184	63.9396	76770.8243	66.3792	81056.5312
59	66.8831	99953.2938	.2456	739.1640	46.0700	76816.8943	47.4445	81104.0456
60	51.1083	100004.4021	.1653	739.3293	35.1523	76852.0466	36.1108	81140.1564
61	40.6367	100045.0388	.1172	739.4465	27.9361	76879.9827	28.6159	81168.7723
62	33.0541	100078.0929	.0847	739.5312	22.7166	76902.6995	23.2083	81191.9806
63	27.1624	100105.2553	.0653	739.5965	18.6881	76921.3876	19.0465	81211.0271
64	22.2109	100127.4662	.0511	739.6476	15.2605	76936.6480	15.5568	81226.5839
65	17.6649	100145.1311	.0401	739.6877	12.1310	76948.7790	12.3636	81238.9475
66	13.3180	100158.4491	.0315	739.7192	9.1431	76957.9221	9.3260	81248.2736
67	9.6395	100168.0886	.0237	739.7429	6.6142	76964.5363	6.7514	81255.0250
68	6.3012	100174.3898	.0158	739.7587	4.3232	76968.8595	4.4147	81259.4396
69	3.1419	100177.5317	.0079	739.7665	2.1558	76970.9952	2.2015	81261.6411

76971. BCF--MAX GAS PRODUCED IN SCENARIO

TABLE E-4(4)f

ECONOMIC SUMMARY

PROFIT INDICATORS

DISCOUNTED PRESENT WORTH AT 15.0 PCT. (MM$)	2666.08669
DCF RATE OF RETURN (PERCENT)	47.40
PAYOUT TIME (YEARS)	12.34
PROFIT PER INVESTMENT ($/$)	3.408
MAX. UNRECOVERED INVESTMENT (MM$)	324.0096
NET CASH RECOVERY AFTER TAX (MM$)	100177.5317
EXPLORATION EXPENDITURE (MM$)	12108.6938
PRODUCTION INVESTMENT (MM$)	18222.9742
TOTAL INVESTMENT (MM$)	29395.9026
OPERATING EXPENSE (MM$)	8842.2427

TABLE E-4(5)a

Standard Scenario at $3.50 and 15%
Base and Advanced Technologies--Eastern U.S.

CASE 7.31 SCENARIO 1 08/14/80 20 YEAR DEVELOPMENT PROGRAM

		YEAR OF DEVELOPMENT / LOCATION OF PROSPECTS--		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	
1	1202142	ERN CNTRL SHALLOW A	15.0,3.50	1	2	3	4	8	8	9	9	9	9	0	0	0	0	0	0	0	0	0	0	62
2	1217142	ERN CNTRL SHALLOW B	15.0,3.50	1	1	2	4	5	5	5	5	5	5	0	0	0	0	0	0	0	0	0	0	38
3	1218142	ERN CNTRL SHALLOW C	15.0,3.50	1	1	2	5	5	5	5	5	5	5	0	0	0	0	0	0	0	0	0	0	39
4	1220142	ERN CNTRL SHALLOW D	15.0,3.50	4	4	8	20	20	21	21	21	21	21	0	0	0	0	0	0	0	0	0	0	161
5	1301142	EASTERN COASTAL	15.0,3.50	10	15	20	30	40	43	43	43	43	44	0	0	0	0	0	0	0	0	0	0	331
6	1302142	EASTERN COASTAL	15.0,3.50	5	10	15	20	25	27	29	29	29	30	0	0	0	0	0	0	0	0	0	0	219
7	1303142	EASTERN COASTAL	15.0,3.50	3	6	9	12	12	12	12	12	12	12	0	0	0	0	0	0	0	0	0	0	102
8	1307142	EASTERN COASTAL	15.0,3.50	13	15	20	30	40	50	50	50	55	55	0	0	0	0	0	0	0	0	0	0	378
9	1601142	ERN CNTRL INTERMED	15.0,3.50	3	5	7	12	13	14	14	14	14	14	0	0	0	0	0	0	0	0	0	0	110
10	1202242	ERN CNTRL SHALLOW A	15.0,3.50	0	0	0	0	2	3	4	4	5	10	15	20	20	20	20	20	20	21	21	21	226
11	1217242	ERN CNTRL SHALLOW B	15.0,3.50	0	0	0	0	2	4	6	8	9	15	25	30	35	35	35	35	35	35	35	35	379
12	1218242	ERN CNTRL SHALLOW C	15.0,3.50	0	0	0	0	2	3	3	4	5	10	15	16	16	16	16	16	16	16	16	16	186
13	1220242	ERN CNTRL SHALLOW D	15.0,3.50	0	0	0	0	2	3	4	5	5	7	10	10	11	11	11	11	11	11	11	11	134
14	1301242	EASTERN COASTAL	15.0,3.50	0	0	0	0	0	2	4	10	10	13	15	15	15	15	15	15	15	15	15	15	189
15	1302242	EASTERN COASTAL	15.0,3.50	0	0	0	0	0	1	3	5	5	5	6	7	7	7	7	7	7	7	8	9	91
16	1303242	EASTERN COASTAL	15.0,3.50	0	0	0	0	0	1	1	2	3	3	3	3	3	3	3	3	3	3	3	3	40
17	1307242	EASTERN COASTAL	15.0,3.50	0	0	0	0	0	1	5	10	15	18	18	18	18	18	18	18	18	18	18	18	229
18	1601242	ERN CNTRL INTERMED	15.0,3.50	0	0	0	1	4	7	10	10	10	10	10	10	10	10	10	10	10	10	10	10	152
19	2101142	ERN CNTRL DEEP	15.0,3.50	1	1	2	5	5	5	5	5	5	5	0	0	0	0	0	0	0	0	0	0	39
20	2101242	ERN CNTRL DEEP	15.0,3.50	0	0	0	0	2	3	4	4	5	10	15	20	20	20	20	20	23	25	25	25	241

TABLE E-4(5)b

SUMMARY OF WELL REQUIREMENTS

	CASE	LOCATION OF PROSPECT		NO. PROSP.	WILDCAT WELLS PROD.	WILDCAT WELLS DRY	WILDCAT WELLS TOTAL	W/C SUCCESS RATIO	DEVELOPMENT WELLS PROD.	DEVELOPMENT WELLS DRY	DEVELOPMENT WELLS TOTAL	TOTAL ALL WELLS
1	1202142	ERN CNTRL SHALLOW A	15.0,3.50	62	18	100	118	.16	411	102	513	631
2	1217142	ERN CNTRL SHALLOW B	15.0,3.50	38	7	66	73	.10	76	19	95	168
3	1218142	ERN CNTRL SHALLOW C	15.0,3.50	39	11	62	73	.16	227	56	283	356
4	1220142	ERN CNTRL SHALLOW D	15.0,3.50	161	48	256	304	.16	478	119	597	901
5	1301142	EASTERN COASTAL	15.0,3.50	331	136	194	330	.41	804	201	1005	1335
6	1302142	EASTERN COASTAL	15.0,3.50	219	67	151	218	.31	805	201	1006	1224
7	1303142	EASTERN COASTAL	15.0,3.50	102	33	68	101	.33	505	126	631	732
8	1307142	EASTERN COASTAL	15.0,3.50	378	62	315	377	.17	1199	299	1498	1875
9	1601142	ERN CNTRL INTERMED	15.0,3.50	110	19	108	127	.15	628	157	785	912
10	1202242	ERN CNTRL SHALLOW A	15.0,3.50	226	75	361	436	.17	809	202	1011	1447
11	1217242	ERN CNTRL SHALLOW B	15.0,3.50	379	73	665	738	.10	383	95	478	1216
12	1218242	ERN CNTRL SHALLOW C	15.0,3.50	186	96	296	392	.16	620	155	775	1127
13	1220242	ERN CNTRL SHALLOW D	15.0,3.50	134	53	200	253	.21	462	115	577	830
14	1301242	EASTERN COASTAL	15.0,3.50	189	96	92	188	.51	248	62	310	498
15	1302242	EASTERN COASTAL	15.0,3.50	91	12	78	90	.13	130	32	162	252
16	1303242	EASTERN COASTAL	15.0,3.50	40	12	27	39	.32	240	60	300	339
17	1307242	EASTERN COASTAL	15.0,3.50	229	38	190	228	.17	526	131	657	885
18	1601242	ERN CNTRL INTERMED	15.0,3.50	152	85	90	175	.49	1250	312	1562	1737
19	2101142	ERN CNTRL DEEP	15.0,3.50	39	10	34	44	.23	122	30	152	196
20	2101242	ERN CNTRL DEEP	15.0,3.50	241	82	192	274	.30	391	97	488	762

TABLE E-4(5)c

ANNUAL DRILLING SCHEDULE

	PROSPECT	YEAR	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
1	ERN CNTRL SHALLOW A	15.0,3.50	10	20	30	40	81	81	91	91	91	91	0	0	0	0	0	0	0	0	0	0
2	ERN CNTRL SHALLOW B	15.0,3.50	4	4	8	17	22	22	22	22	22	22	0	0	0	0	0	0	0	0	0	0
3	ERN CNTRL SHALLOW C	15.0,3.50	9	9	18	45	45	45	45	45	45	45	0	0	0	0	0	0	0	0	0	0
4	ERN CNTRL SHALLOW D	15.0,3.50	22	22	44	112	112	117	117	117	117	117	0	0	0	0	0	0	0	0	0	0
5	EASTERN COASTAL	15.0,3.50	40	60	80	121	161	173	173	173	173	177	0	0	0	0	0	0	0	0	0	0
6	EASTERN COASTAL	15.0,3.50	27	55	83	111	139	151	162	162	162	167	0	0	0	0	0	0	0	0	0	0
7	EASTERN COASTAL	15.0,3.50	21	43	64	86	86	86	86	86	86	86	0	0	0	0	0	0	0	0	0	0
8	EASTERN COASTAL	15.0,3.50	54	74	99	148	198	248	248	248	273	273	0	0	0	0	0	0	0	0	0	0
9	ERN CNTRL INTERMED	15.0,3.50	18	31	44	75	81	88	88	88	88	88	0	0	0	0	0	0	0	0	0	0
10	ERN CNTRL SHALLOW A	15.0,3.50	0	0	0	0	12	19	25	25	32	64	96	128	128	128	128	128	128	134	134	134
11	ERN CNTRL SHALLOW B	15.0,3.50	0	0	0	0	6	12	19	25	26	48	80	96	112	112	112	112	112	112	112	112
12	ERN CNTRL SHALLOW C	15.0,3.50	0	0	0	0	12	16	18	24	30	60	91	97	97	97	97	97	97	97	97	97
13	ERN CNTRL SHALLOW D	15.0,3.50	0	0	0	0	12	16	24	31	31	43	62	62	68	68	68	68	68	68	68	68
14	EASTERN COASTAL	15.0,3.50	0	0	0	0	0	5	10	26	26	34	39	39	39	39	39	39	39	39	39	39
15	EASTERN COASTAL	15.0,3.50	0	0	0	0	0	2	8	13	13	13	16	19	19	19	19	19	19	19	22	25
16	EASTERN COASTAL	15.0,3.50	0	0	0	0	0	8	8	17	25	25	25	25	25	25	25	25	25	25	25	25
17	EASTERN COASTAL	15.0,3.50	0	0	0	0	0	3	19	38	58	69	69	69	69	69	69	69	69	69	69	69
18	ERN CNTRL INTERMED	15.0,3.50	0	0	0	11	45	80	114	114	114	114	114	114	114	114	114	114	114	114	114	114
19	ERN CNTRL DEEP	15.0,3.50	5	5	10	25	25	25	25	25	25	25	0	0	0	0	0	0	0	0	0	0
20	ERN CNTRL DEEP	15.0,3.50	0	0	0	0	6	9	12	12	15	31	47	63	63	63	63	63	72	79	79	79
	TOTAL WELLS IN EACH YEAR		220	323	480	791	1043	1210	1314	1382	1454	1592	639	712	734	734	734	734	743	756	759	762

TABLE E-4(5)d

INVESTMENT REQUIREMENTS AND RESERVE ADDITIONS

YEAR	INVESTMENT (MM$)	GAS RESERVES ADDED (BCF)	CUMMULATIVE GAS RESERVES
1	128.8	208.5	208.5
2	192.1	315.0	524.5
3	279.7	474.5	999.0
4	440.1	785.8	1784.8
5	577.6	1043.8	2828.6
6	688.8	1229.5	4058.1
7	755.4	1358.0	5416.1
8	807.8	1453.1	6869.3
9	863.6	1527.2	8396.5
10	947.1	1738.9	10135.4
11	425.3	959.0	11094.4
12	472.3	1091.7	12186.1
13	482.1	1121.6	13307.7
14	482.1	1121.6	14429.3
15	482.1	1121.6	15550.9
16	482.1	1121.6	16672.5
17	496.0	1162.5	17835.0
18	507.6	1196.7	19031.7
19	509.7	1198.9	20230.6
20	511.7	1201.1	21431.7
	10532.3 TOTAL INVESTMENT		

TABLE E-4(5)e

CASH FLOW AND PRODUCTION SUMMARY

YEAR	ANNUAL CASH FLOW (MM$)	CUMUL. CASH FLOW (MM$)	ANNUAL NGL PRODN (MMB)	CUMUL. NGL PRODN (MMB)	ANNUAL GAS PRODN (BCF)	CUMUL. GAS PRODN (BCF)	ANNUAL GAS PRODN (BCF EQI)	CUMUL. GAS PRODN (BCF EQI)
1	-.0375	-.0375	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2	-8.0693	-9.5069	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
3	-26.7604	-36.2672	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
4	-37.9460	-74.2132	.0439	.0439	3.5693	3.5693	3.6240	3.6240
5	-69.3392	-143.7524	.1969	.2428	15.6427	19.2121	16.7962	20.6202
6	-81.8253	-225.5777	.4967	.7335	38.8394	58.0514	41.6857	62.3059
7	-84.4479	-310.0257	.8971	1.6306	71.9806	130.0320	77.1837	139.4896
8	-74.3901	-384.7158	1.4401	3.0707	118.7550	248.7870	127.1422	266.6318
9	-43.6326	-428.3486	2.1156	5.1923	179.9780	428.7650	192.2483	458.8800
10	7.9021	-420.4465	2.8684	8.0607	251.6837	680.4487	268.3205	727.2005
11	83.9627	-336.4838	3.6457	11.7064	328.1202	1008.5688	349.2654	1076.4659
12	198.7177	-140.1661	4.4290	16.1354	404.9824	1413.5512	430.6707	1507.1366
13	331.9642	183.5181	5.2883	21.4237	486.0935	1899.6447	516.7655	2023.9021
14	415.1434	598.9615	6.0233	27.4469	555.4873	2455.1320	590.4222	2614.3243
15	578.9955	1177.9565	6.4181	33.8650	594.6327	3054.7647	636.6576	3251.1819
16	631.4319	1809.3884	6.4644	40.3294	617.3541	3672.1188	654.8477	3906.0296
17	672.3634	2482.2218	6.5389	46.8684	637.6499	4309.7687	675.7757	4581.3053
18	707.7987	3190.0505	6.6500	53.5263	661.7843	4971.7530	700.4005	5282.2058
19	742.2450	3932.2955	6.8278	60.3541	686.4919	5660.2449	728.0930	6010.2988
20	780.4551	4712.7506	7.0655	67.4196	717.4060	6377.6508	758.3859	6768.6847
21	828.2639	5541.0145	7.3443	74.7640	747.2432	7124.8940	789.8403	7558.5250
22	900.3041	6441.3186	7.6303	82.3943	776.9819	7901.8759	821.2379	8379.7629
23	1014.8949	7456.7135	7.9193	90.3136	806.6642	8708.5401	852.5961	9232.3590
24	1034.0285	8490.7420	7.7516	98.0652	806.3683	9514.9084	851.3279	10083.6868
25	1068.0757	9558.8178	7.3978	105.4631	786.0773	10300.9857	828.9846	10912.6714
26	1040.5932	10599.5109	6.9501	112.4131	746.8377	11047.8234	787.1482	11699.8196
27	995.1551	11594.6660	6.5234	118.9366	707.1849	11755.0083	745.0208	12444.8404
28	945.2376	12539.9036	6.1372	125.0738	671.8477	12426.8560	707.4435	13152.2839
29	900.3429	13440.2465	5.7659	130.8397	640.7967	13067.6526	674.3551	13826.6389
30	859.4011	14299.6476	5.4566	136.3163	612.4486	13680.1012	644.0971	14470.7360
31	820.5369	15120.2845	5.1470	141.4634	586.0372	14266.1385	615.8900	15086.6260
32	783.5194	15903.8039	4.8613	146.3247	561.6961	14827.8345	589.8918	15676.5178
33	749.1518	16653.0556	4.6047	150.9294	539.4271	15367.2616	566.1346	16242.6524
34	716.8358	17369.8915	4.3775	155.3069	518.8536	15886.1152	544.2430	16786.8954
35	686.5245	18055.4160	4.1748	159.4817	499.5466	16385.7618	523.8603	17310.7557
36	657.4715	18713.0878	3.9890	163.4707	481.0184	16865.7802	504.1547	17814.9104
37	629.3581	19342.9459	3.8159	167.2866	462.4829	17329.2632	484.8152	18299.5256
38	600.3965	19943.0364	3.6513	170.9379	443.2678	17772.5310	464.4455	18763.9711
39	569.6428	20512.6793	3.4917	174.4296	422.7044	18195.2354	442.9562	19206.9272
40	538.8456	21051.0249	3.3326	177.7622	400.8919	18596.1273	420.2210	19627.1482
41	509.8230	21556.8479	3.1716	180.9339	378.0044	18974.1316	396.3993	20023.5481
42	481.8901	22038.7380	3.0111	183.9449	355.9077	19330.0394	373.1719	20394.9201
43	456.8340	22495.5720	2.8500	186.7950	338.8368	19656.8762	355.3689	20740.2890
44	431.3745	22806.9465	2.6911	189.4861	303.3280	19960.2041	318.9364	21059.2254
45	366.9033	23233.8498	2.5321	192.0211	278.4113	20238.6175	293.1147	21352.3401
46	334.3925	23568.2423	2.3778	194.3990	254.8607	20493.4782	268.6522	21620.9923
47	302.0782	23871.1205	2.2221	196.6210	232.1689	20725.6472	245.0569	21866.0492
48	271.0427	24142.1633	2.0593	198.6804	209.2752	20934.9224	221.2192	22087.2684
49	239.8665	24382.0518	1.8912	200.5716	186.8376	21121.7601	197.8070	22285.0754
50	209.2826	24591.3344	1.7216	202.2932	164.6287	21286.3889	174.8140	22459.8894
51	178.4178	24769.7522	1.5413	203.8345	142.2441	21428.6330	151.1839	22611.0734
52	148.8073	24918.5595	1.3552	205.1897	120.3687	21549.2016	128.2287	22739.3021
53	120.2771	25038.8366	1.1665	206.3562	99.1044	21648.3060	105.6354	22845.1374
54	92.4826	25131.3192	.9518	207.3081	78.0742	21726.3803	83.5949	22928.7323
55	66.9422	25198.2614	.7480	208.0561	58.4766	21784.8568	62.8032	22991.5356
56	45.5452	25243.8067	.5556	208.6036	41.6690	21826.5258	44.8914	23036.4270
57	29.7089	25273.5156	.3951	208.9987	28.7997	21855.3255	31.0910	23067.5180
58	18.5240	25292.0425	.2756	209.2743	19.1384	21874.4639	20.7369	23088.2549
59	10.6495	25302.6920	.1800	209.4543	11.6980	21886.1620	12.7420	23100.9970
60	4.5310	25307.2230	.0983	209.5526	5.4626	21891.6246	6.0325	23107.0294
61	3.5465	25310.7695	.0835	209.6362	4.2265	21895.8511	5.0114	23112.0408
62	2.7379	25313.5074	.0695	209.7057	3.7154	21899.8665	4.1166	23116.1594
63	2.0473	25315.5547	.0565	209.7622	2.9858	21902.8523	3.3136	23119.4730
64	1.4543	25317.0090	.0442	209.8064	2.3289	21905.1812	2.5852	23122.0582
65	.9669	25317.9779	.0334	209.8398	1.7506	21906.9317	1.9444	23124.0025
66	.6206	25318.5984	.0244	209.8641	1.2707	21908.2024	1.4119	23125.4144
67	.3357	25318.9342	.0163	209.8804	.8493	21909.0517	.9436	23126.3580
68	.1180	25319.0522	.0092	209.8896	.4789	21909.5306	.5325	23126.8905
69	.0491	25319.1013	.0042	209.8938	.2170	21909.7475	.2411	23127.1315

21910. BCF--MAX GAS PRODUCED IN SCENARIO

TABLE E-4(5)f

ECONOMIC SUMMARY

PROFIT INDICATORS

DISCOUNTED PRESENT WORTH AT 15.0 PCT. (MM$)	745.61648
DCF RATE OF RETURN (PERCENT)	30.10
PAYOUT TIME (YEARS)	11.45
PROFIT PER INVESTMENT ($/$)	2.404
MAX. UNRECOVERED INVESTMENT (MM$)	428.3486
NET CASH RECOVERY AFTER TAX (MM$)	25319.1013
EXPLORATION EXPENDITURE (MM$)	3276.9417
PRODUCTION INVESTMENT (MM$)	7476.5030
TOTAL INVESTMENT (MM$)	10532.2510
OPERATING EXPENSE (MM$)	6435.7694

TABLE E-4(6)a

Standard Scenario at $3.50 and 15%
Base and Advanced Technologies--Mid-Continent U.S.

20 YEAR DEVELOPMENT PROGRAM

	YEAR OF DEVELOPMENT		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	
	LOCATION OF PROSPECTS--																						
1	1202142	MIDCON SHALLOW FMN A 15.0,3.50	0	0	1	3	3	3	4	4	4	2	0	0	0	0	0	0	0	0	0	0	24
2	1217142	MIDCON SHALLOW FMN B 15.0,3.50	1	1	2	2	4	5	5	6	6	8	0	0	0	0	0	0	0	0	0	0	40
3	1218142	MIDCON SHALLOW FMN C 15.0,3.50	0	0	1	3	3	3	4	4	4	2	0	0	0	0	0	0	0	0	0	0	24
4	1220142	MIDCON SHALLOW FMN D 15.0,3.50	0	2	2	2	2	4	4	4	3	3	0	0	0	0	0	0	0	0	0	0	26
5	1501142	MIDCON DEEP 15.0,3.50	1	2	3	3	3	3	3	3	3	2	0	0	0	0	0	0	0	0	0	0	26
6	1301142	MIDCON INTERMEDIATE 15.0,3.50	1	1	2	2	2	2	2	2	3	3	0	0	0	0	0	0	0	0	0	0	20
7	1202242	MIDCON SHALLOW FMN A 15.0,3.50	0	0	0	0	0	0	0	0	1	3	4	4	4	4	4	4	4	4	4	4	44
8	1217242	MIDCON SHALLOW FMN B 15.0,3.50	0	0	0	0	0	0	0	0	1	2	3	5	7	8	8	8	8	8	9	10	77
9	1218242	MIDCON SHALLOW FMN C 15.0,3.50	0	0	0	0	0	0	0	0	0	0	4	4	4	4	4	4	4	4	4	4	40
10	1220242	MIDCON SHALLOW FMN D 15.0,3.50	0	0	0	0	0	0	0	0	0	0	4	4	4	4	4	4	4	4	4	4	40
11	1601242	MIDCON DEEP 15.0,3.50	0	0	0	0	0	0	0	0	2	2	2	3	3	3	3	3	3	3	3	2	32
12	1801242	MIDCON INTERMEDIATE 15.0,3.50	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	0	11

TABLE E-4(6)b

SUMMARY OF WELL REQUIREMENTS

	CASE	LOCATION OF PROSPECT	NO. PROSP.	WILDCAT WELLS PROD.	WILDCAT WELLS DRY	WILDCAT WELLS TOTAL	W/C SUCCESS RATIO	DEVELOPMENT WELLS PROD.	DEVELOPMENT WELLS DRY	DEVELOPMENT WELLS TOTAL	TOTAL ALL WELLS
1	1202142	MIDCON SHALLOW FMN A 15.0,3.50	24	7	38	45	.16	159	39	198	243
2	1217142	MIDCON SHALLOW FMN B 15.0,3.50	40	7	70	77	.10	80	20	100	177
3	1218142	MIDCON SHALLOW FMN C 15.0,3.50	24	7	38	45	.16	139	34	173	218
4	1220142	MIDCON SHALLOW FMN D 15.0,3.50	26	7	41	48	.16	77	19	96	144
5	1501142	MIDCON DEEP 15.0,3.50	26	4	25	29	.15	148	37	185	214
6	1301142	MIDCON INTERMEDIATE 15.0,3.50	20	0	0	0	I	0	0	0	0
7	1202242	MIDCON SHALLOW FMN A 15.0,3.50	44	14	70	84	.17	157	39	196	280
8	1217242	MIDCON SHALLOW FMN B 15.0,3.50	77	14	135	149	.10	77	19	96	245
9	1218242	MIDCON SHALLOW FMN C 15.0,3.50	40	12	63	75	.16	133	33	166	241
10	1220242	MIDCON SHALLOW FMN D 15.0,3.50	40	16	59	75	.21	138	34	172	247
11	1501242	MIDCON DEEP 15.0,3.50	32	18	19	37	.49	263	65	328	365
12	1801242	MIDCON INTERMEDIATE 15.0,3.50	11	4	10	14	.29	143	35	178	192

TABLE E-4(6)c

ANNUAL DRILLING SCHEDULE

	PROSPECT	YEAR	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
1	MIDCON SHALLOW FMN A	15.0,3.50	0	0	10	30	30	30	40	40	40	20	0	0	0	0	0	0	0	0	0	0
2	MIDCON SHALLOW FMN B	15.0,3.50	4	4	8	8	17	22	36	36	26	35	0	0	0	0	0	0	0	0	0	0
3	MIDCON SHALLOW FMN C	15.0,3.50	0	0	9	27	27	27	36	36	36	18	0	0	0	0	0	0	0	0	0	0
4	MIDCON SHALLOW FMN D	15.0,3.50	0	11	11	11	11	22	22	22	16	16	0	0	0	0	0	0	0	0	0	0
5	MIDCON DEEP	15.0,3.50	6	12	18	18	18	18	18	18	18	12	0	0	0	0	0	0	0	0	0	0
6	MIDCON INTERMEDIATE	15.0,3.50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	MIDCON SHALLOW FMN A	15.0,3.50	0	0	0	0	0	0	0	0	6	19	25	25	25	25	25	25	25	25	25	25
8	MIDCON SHALLOW FMN B	15.0,3.50	0	0	0	0	0	0	0	0	3	6	9	16	22	25	25	25	25	25	28	32
9	MIDCON SHALLOW FMN C	15.0,3.50	0	0	0	0	0	0	0	0	0	0	24	24	24	24	24	24	24	24	24	24
10	MIDCON SHALLOW FMN D	15.0,3.50	0	0	0	0	0	0	0	0	0	0	24	24	24	24	24	24	24	24	24	24
11	MIDCON DEEP	15.0,3.50	0	0	0	0	0	0	0	0	22	22	22	34	34	34	34	34	34	34	34	22
12	MIDCON INTERMEDIATE	15.0,3.50	0	0	0	0	0	0	0	0	17	17	17	17	17	17	17	17	17	17	17	0
	TOTAL WELLS IN EACH YEAR		10	27	56	94	103	119	138	142	184	165	121	140	146	149	149	149	149	149	152	127

TABLE E-4(6)d

INVESTMENT REQUIREMENTS AND RESERVE ADDITIONS

YEAR	INVESTMENT (MM$)	GAS RESERVES ADDED (BCF)	CUMMULATIVE GAS RESERVES
1	8.1	15.4	15.4
2	14.6	36.4	51.8
3	27.7	60.2	108.0
4	37.6	84.8	192.8
5	40.2	93.2	286.0
6	44.6	108.9	394.9
7	49.6	121.2	516.0
8	50.9	125.4	641.4
9	82.7	190.3	831.8
10	76.3	186.8	1018.6
11	63.0	152.2	1170.8
12	73.6	177.0	1347.7
13	76.3	185.6	1533.3
14	77.6	189.9	1723.2
15	77.6	189.9	1913.1
16	77.6	189.9	2103.0
17	77.6	189.9	2292.8
18	77.6	189.9	2482.7
19	78.9	194.2	2676.9
20	62.1	161.0	2837.9
	1176.2 TOTAL INVESTMENT		

TABLE E-4(6)e

CASH FLOW AND PRODUCTION SUMMARY

YEAR	ANNUAL CASH FLOW (MM$)	CUMUL. CASH FLOW (MM$)	ANNUAL NGL PRODN (MMB)	CUMUL. NGL PRODN (MMB)	ANNUAL GAS PRODN (BCF)	CUMUL. GAS PRODN (BCF)	ANNUAL GAS PRODN (BCF EQI)	CUMUL. GAS PRODN (BCF EQI)
1	-.0564	-.0564	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2	-.9586	-1.0151	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
3	-2.4767	-3.4918	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
4	-5.1811	-8.6729	.0005	.0005	.1496	.1496	.1526	.1526
5	-7.3294	-16.0023	.0022	.0027	.6877	.8372	.7065	.8591
6	-9.9072	-26.4095	.0054	.0081	1.8754	2.7126	1.9065	2.7596
7	-10.3007	-36.7102	.0165	.0249	4.3303	7.0429	4.4277	7.1873
8	-10.4178	-47.1280	.0264	.0513	7.6355	14.6784	7.7886	14.9759
9	-7.1020	-54.2300	.0424	.0937	12.2439	26.9223	12.4901	27.4660
10	-3.5171	-57.7471	.0557	.1494	17.1939	44.1162	17.5170	44.9829
11	.2858	-57.4613	.0677	.2171	22.4654	66.5816	22.8579	67.8408
12	6.1748	-51.2865	.0827	.2998	28.7611	95.3427	29.2408	97.0816
13	12.2721	-39.0144	.0996	.3994	35.7131	131.0558	36.2907	133.3723
14	21.2246	-17.7898	.1151	.5145	42.4493	173.5052	43.1167	176.4890
15	33.1044	15.3146	.1647	.6792	51.1561	224.6612	52.1115	228.6005
16	44.1837	59.4983	.2055	.8847	59.2530	283.9142	60.4447	289.0452
17	52.6429	112.1414	.2218	1.1065	66.0275	349.9417	67.3141	356.3593
18	61.5672	173.7086	.2428	1.3493	73.2050	423.1467	74.6131	430.9724
19	70.7430	244.4516	.2647	1.6139	80.3561	503.5029	81.8912	512.8636
20	79.5582	324.0098	.2862	1.9001	87.2510	590.7539	88.9111	601.7747
21	89.3947	413.4045	.3065	2.2067	93.6352	684.3891	95.6130	697.3878
22	103.8221	517.2266	.3257	2.5323	100.2308	784.6200	102.1197	799.5075
23	121.7931	639.0197	.3419	2.8743	106.1186	890.9386	108.1019	907.6094
24	129.4930	768.5128	.3518	3.2261	109.2728	1000.2114	111.3133	1018.9227
25	139.4909	908.5037	.3574	3.5835	109.7420	1109.9534	111.8151	1130.7378
26	139.5981	1048.1018	.3345	3.9180	105.3420	1215.2953	107.2820	1238.0197
27	135.5767	1183.6805	.3180	4.2360	100.5707	1315.8661	102.4152	1340.4350
28	130.1929	1313.8734	.3031	4.5392	96.2421	1412.1082	98.0004	1438.4353
29	125.3352	1439.2086	.2892	4.8283	92.4385	1504.5467	94.1157	1532.5511
30	120.7866	1559.9972	.2757	5.1040	88.9457	1593.4923	90.5445	1623.0956
31	116.3756	1676.3728	.2630	5.3670	85.7129	1679.2053	87.2382	1710.3338
32	112.0103	1788.3831	.2518	5.6188	82.7452	1761.9505	84.2056	1794.5394
33	107.9733	1896.3565	.2422	5.8610	80.0604	1842.0109	81.4653	1876.0046
34	104.2406	2000.5970	.2337	6.0947	77.6017	1919.6126	78.9571	1954.9618
35	100.8947	2101.4917	.2259	6.3206	75.2967	1994.9094	76.6069	2031.5686
36	97.2314	2198.5231	.2184	6.5390	73.0048	2067.9142	74.2717	2105.8403
37	93.7761	2292.2991	.2112	6.7502	70.6604	2138.5746	71.8853	2177.7256
38	90.1998	2382.4989	.2041	6.9543	68.1831	2206.7577	69.3669	2247.0925
39	86.4253	2468.9243	.1973	7.1516	65.4967	2272.2543	66.6411	2313.7337
40	82.4422	2551.3664	.1908	7.3424	62.5892	2334.8435	63.6958	2377.4294
41	78.4098	2629.7763	.1847	7.5271	59.6080	2394.4515	60.6794	2438.1089
42	74.2123	2703.9886	.1791	7.7063	56.4854	2450.9369	57.5243	2495.6332
43	69.7525	2773.7411	.1734	7.8796	53.1449	2504.0818	54.1506	2549.7838
44	65.0333	2838.7745	.1671	8.0468	49.5968	2553.6787	50.5662	2600.3500
45	60.2734	2899.0479	.1605	8.2073	45.9991	2599.6777	46.9303	2647.2802
46	55.4595	2954.5074	.1530	8.3603	42.3623	2642.0401	43.2496	2690.5298
47	50.9048	3004.8122	.1433	8.5036	38.4917	2680.5318	39.3230	2729.8528
48	44.8149	3049.6271	.1311	8.6347	34.3533	2714.8851	35.1138	2764.9666
49	39.2084	3088.8355	.1166	8.7533	30.1161	2745.0012	30.8038	2795.7703
50	33.4678	3122.3033	.1053	8.8586	25.7735	2770.7747	26.3843	2822.1546
51	27.7187	3150.0221	.0910	8.9496	21.4079	2792.1826	21.9356	2844.0902
52	22.1599	3172.1820	.0764	9.0260	17.1742	2809.3568	17.6172	2861.7074
53	16.9437	3189.1257	.0613	9.0873	13.1880	2822.5448	13.5435	2875.2509
54	12.2928	3201.4186	.0475	9.1349	9.6152	2832.1600	9.8914	2885.1423
55	8.3168	3209.7354	.0356	9.1705	6.5520	2838.7120	6.7587	2891.9011
56	5.1244	3214.8597	.0251	9.1956	4.0771	2842.7891	4.2224	2896.1234
57	2.9462	3217.8059	.0162	9.2118	2.3729	2845.1620	2.4669	2898.5904
58	1.4862	3219.2922	.0096	9.2214	1.2117	2846.3736	1.2673	2899.8577
59	.7000	3219.9921	.0052	9.2266	.5627	2846.9363	.5929	2900.4506
60	.2202	3220.2124	.0015	9.2281	.1582	2847.0945	.1670	2900.6175
61	.1067	3220.3191	.0008	9.2289	.0756	2847.1701	.0802	2900.6977
62	.0429	3220.3620	.0003	9.2292	.0307	2847.2008	.0325	2900.7302
63	.0094	3220.3714	.0000	9.2293	.0070	2847.2076	.0073	2900.7375
64	.0020	3220.3734	0.0000	9.2293	.0015	2847.2093	.0015	2900.7390

2847. BCF--MAX GAS PRODUCED IN SCENARIO

TABLE E-4(6)f

ECONOMIC SUMMARY

PROFIT INDICATORS

DISCOUNTED PRESENT WORTH AT 15.0 PCT. (MM$)	60.77550
DCF RATE OF RETURN (PERCENT)	24.70
PAYOUT TIME (YEARS)	13.54
PROFIT PER INVESTMENT ($/$)	2.738
MAX. UNRECOVERED INVESTMENT (MM$)	57.7471
NET CASH RECOVERY AFTER TAX (MM$)	3220.3734
EXPLORATION EXPENDITURE (MM$)	351.7720
PRODUCTION INVESTMENT (MM$)	846.6105
TOTAL INVESTMENT (MM$)	1176.2169
OPERATING EXPENSE (MM$)	874.2117

TABLE E-5

Standard Scenario

($2.50 @ 15%)

Year 1981

	Pro-duction (TCF/Yr.)	Production Cumulative (TCF)	Investment ($ Billion)	No.Pro-spects /Yr.	No.Wells /Yr.	Reserves Added (TCF/Yr.)	Reserves Cumula-tive (TCF)	Percent 500 TCF Produced	Percent 500 TCF Added to Reserve
No. Great Plains/Williston			.057	30	200	.191	.191		
Eastern			.058	26	117	.144	.144		
Western			.090	29	144	.169	.169		
Mid-Continent			.001	1	3	.004	.004		
Gr. Southwest			.021	6	18	.054	.054		
Southwest			.050	15	49	.128	.128		
Rocky Mts.			.175	45	189	.366	.366		
Total			.452	152	720	1.056	1.056		

TABLE E-5 (Continued)

Standard Scenario

($2.50 @ 15%)

Year 1985

	Pro-duction (TCF/Yr.)	Production Cumulative (TCF)	Investment ($ Billion)	No. Pro-spects /Yr.	No. Wells /Yr.	Reserves Added (TCF/Yr.)	Reserves Cumula-tive (TCF)	Percent 500 TCF Produced	Percent 500 TCF Added to Reserve
No. Great Plains/Williston	.006	.007	.181	97	619	.640	2.000		
Eastern	.009	.011	.329	118	564	.758	1.871		
Western	.014	.019	.200	60	314	.377	1.214		
Mid-Continent	0	0	.019	12	69	.057	.156		
Gr. Southwest	.005	.007	.210	42	211	.491	1.161		
Southwest	.012	.015	.211	54	219	.506	1.483		
Rocky Mts.	.060	.080	.544	134	567	1.207	4.169		
Total	.106	.139	1.694	517	2,563	4.036	12.054		

TABLE E-5 (Continued)

Standard Scenario

($2.50 @ 15%)

Year 1990

	Pro-duction (TCF/Yr.)	Production Cumulative (TCF)	Investment ($ Billion)	No. Pro-spects /Yr.	No. Wells /Yr.	Reserves Added (TCF/Yr.)	Reserves Cumula-tive (TCF)	Percent 500 TCF Produced	Percent 500 TCF Added to Reserve
No. Great Plains/Williston	.120	.321	.312	144	743	1.018	6.454		
Eastern	.156	.408	.470	146	798	1.151	6.910		
Western	.127	.382	.275	83	386	.553	3.789		
Mid-Continent	.010	.023	.067	24	155	.173	.723		
Gr. Southwest	.129	.313	1.065	178	1,098	2.759	9.684		
Southwest	.131	.355	.459	83	351	1.162	6.243		
Rocky Mts.	.467	1.578	.660	163	510	1.467	10.733		
Total	1.140	3.380	3.308	746	4,041	8.283	44.536		

TABLE E-5 (Continued)

Standard Scenario

($2.50 @ 15%)

Year 1995

	Pro-duction (TCF/Yr.)	Production Cumulative (TCF)	Investment ($ Billion)	No. Pro-spects /Yr.	No. Wells /Yr.	Reserves Added (TCF/Yr.)	Reserves Cumula-tive (TCF)	Percent 500 TCF Produced	Percent 500 TCF Added to Reserve
No. Great Plains/Williston	.326	1.527	.359	162	789	1.156	11.998		
Eastern	.401	1.934	.448	152	703	1.197	12.691		
Western	.261	1.466	.136	43	183	.286	5.652		
Mid-Continent	.040	.146	.118	29	214	.276	1.945		
Gr. Southwest	.900	2.916	2.711	470	2,210	7.284	37.181		
Southwest	.451	1.925	.590	88	397	1.431	13.550		
Rocky Mts.	.809	4.993	.755	178	534	1.594	18.475		
Total	3.188	14.907	5.117	1,122	5,030	13.224	101.492		

TABLE E-5 (Continued)

Standard Scenario

($2.50 @ 15%)

Year 2000

	Pro-duction (TCF/Yr.)	Production Cumulative (TCF)	Investment ($ Billion)	No. Pro-spects /Yr.	No. Wells /Yr.	Reserves Added (TCF/Yr.)	Reserves Cumula-tive (TCF)	Percent 500 TCF Produced	Percent 500 TCF Added to Reserve
No. Great Plains/Williston	.541	3.803	.413	193	936	1.335	18.556		
Eastern	.616	4.617	.280	104	492	.749	17.469		
Western	.269	2.824	.057	20	82	.126	6.571		
Mid-Continent	.094	.507	.076	26	151	.193	3.116		
Gr. Southwest	2.595	12.527	1.606	284	1,554	4.324	66.791		
Southwest	.688	5.044	.273	41	249	.662	18.015		
Rocky Mts.	1.045	9.800	.597	146	455	1.255	25.524		
Total	5.848	39.122	3.302	814	3,919	8.644	156.042		

TABLE E--6

Standard Scenario

($3.50 @ 10%)

Year 1981

	Pro-duction (TCF/Yr.)	Production Cumulative (TCF)	Investment ($ Billion)	No.Pro-spects /Yr.	No.Wells /Yr.	Reserves Added (TCF/Yr.)	Reserves Cumula-tive (TCF)	Percent 500 TCF Produced	Percent 500 TCF Added to Reserve
No. Great Plains/Williston			.021	10	67	.077	.077		
Eastern			.211	42	385	.309	.309		
Western			.234	52	398	.353	.353		
Mid-Continent			.017	3	44	.026	.026		
Gr. Southwest			.088	14	127	.185	.185		
Southwest			.069	14	97	.153	.153		
Rocky Mts.			.290	65	304	.516	.516		
Total			.930						

TABLE E-6 (Continued)

Standard Scenario

($3.50 @ 10%)

Year 1985

	Production (TCF/Yr.)	Production Cumulative (TCF)	Investment ($ Billion)	No. Prospects /Yr.	No. Wells /Yr.	Reserves Added (TCF/Yr.)	Reserves Cumulative (TCF)	Percent 500 TCF Produced	Percent 500 TCF Added to Reserve
No. Great Plains/Williston	.003	.004	.236	93	661	.720	1.741		
Eastern	.021	.026	.937	187	1,759	1.484	4.125		
Western	.027	.035	.395	93	643	.626	2.116		
Mid-Continent	.001	.002	.069	17	204	.127	.422		
Gr. Southwest	.014	.020	.184	25	255	.390	1.368		
Southwest	.012	.015	.305	51	335	.705	1.964		
Rocky Mts.	.075	.101	.588	140	613	1.133	4.253		
Total	.153		2.714						

TABLE E-6 (Continued)

Standard Scenario

($3.50 @ 10%)

Year 1990

	Pro-duction (TCF/Yr.)	Production Cumulative (TCF)	Investment ($ Billion)	No. Pro-spects /Yr.	No. Wells /Yr.	Reserves Added (TCF/Yr.)	Reserves Cumula-tive (TCF)	Percent 500 TCF Produced	Percent 500 TCF Added to Reserve
No. Great Plains/Williston	.123	.284	.516	167	993	1.385	8.253		
Eastern	.344	.933	1.505	301	2,611	2.415	14.444		
Western	.215	.667	.722	151	1,033	1.062	6.999		
Mid-Continent	.025	.070	.118	28	278	.232	1.365		
Gr. Southwest	.168	.411	2.443	188	2,621	5.418	15.938		
Southwest	.186	.474	.619	70	652	1.317	8.288		
Rocky Mts.	.501	1.733	1.207	253	937	1.965	12.139		
Total	1.562		7.130						

TABLE E-6 (Continued)

Standard Scenario

($3.50 @ 10%)

Year 1995

	Pro-duction (TCF/Yr.)	Production Cumulative (TCF)	Investment ($ Billion)	No. Pro-spects /Yr.	No. Wells /Yr.	Reserves Added (TCF/Yr.)	Reserves Cumula-tive (TCF)	Percent 500 TCF Produced	Percent 500 TCF Added to Reserve
No. Great Plains/Williston	.440	1.848	.612	212	1,187	1.662	16.464		
Eastern	.818	4.180	.721	155	1,083	1.404	21.243		
Western	.457	2.589	.445	74	485	.600	9.884		
Mid-Continent	.067	.314	.111	24	197	.226	2.435		
Gr. Southwest	1.514	4.632	3.475	408	3,194	7.693	51.788		
Southwest	.512	2.377	.745	75	572	1.519	15.674		
Rocky Mts.	1.044	5.744	1.816	344	1,368	2.842	25.821		
Total	4.852		7.925						

TABLE E-6 (Continued)

Standard Scenario

($3.50 @ 10%)

Year 2000

	Production (TCF/Yr.)	Production Cumulative (TCF)	Investment ($ Billion)	No. Prospects /Yr.	No. Wells /Yr.	Reserves Added (TCF/Yr.)	Reserves Cumulative (TCF)	Percent 500 TCF Produced	Percent 500 TCF Added to Reserve
No. Great Plains/Williston	.765	5.029	.632	223	1,216	1.731	25.120		
Eastern	.956	8.652	.781	163	1,158	1.523	28.634		
Western	.479	4.911	.445	74	485	.600	12.887		
Mid-Continent	.110	.781	.082	24	157	.182	3.526		
Gr. Southwest	3.304	17.733	3.153	389	2,696	7.156	89.715		
Southwest	.845	5.990	.678	71	467	1.407	23.096		
Rocky Mts.	1.641	12.842	1.769	333	1,339	2.705	39.793		
Total	8.100		7.540						

TABLE E-7

Standard Scenario

($3.50 @ 15%)

Year 1981

	Production (TCF/Yr.)	Production Cumulative (TCF)	Investment ($ Billion)	No. Prospects /Yr.	No. Wells /Yr.	Reserves Added (TCF/Yr.)	Reserves Cumulative (TCF)	Percent 500 TCF Produced	Percent 500 TCF Added to Reserve
No. Great Plains/Williston			.021	10	67	.076	.076		
Eastern			.129	42	220	.208	.208		
Western			.173	52	314	.276	.276		
Mid-Continent			.008	3	10	.015	.015		
Gr. Southwest			.054	14	55	.134	.134		
Southwest			.055	14	63	.133	.133		
Rocky Mts.			.256	65	267	.468	.468		
Total									

TABLE E-7 (Continued)

Standard Scenario

($3.50 @ 15%)

Year 1985

	Pro-duction (TCF/Yr.)	Production Cumulative (TCF)	Investment ($ Billion)	No.Pro-spects /Yr.	No.Wells /Yr.	Reserves Added (TCF/Yr.)	Reserves Cumula-tive (TCF)	Percent 500 TCF Produced	Percent 500 TCF Added to Reserve
No. Great Plains/Williston	.003	.004	.225	93	637	.705	1.711		
Eastern	.016	.019	.578	187	1,043	1.044	2.829		
Western	.023	.030	.301	93	464	.456	1.626		
Mid-Continent	.0	.001	.040	17	103	.093	.286		
Gr. Southwest	.011	.016	.116	25	114	.302	1.033		
Southwest	.010	.014	.222	51	201	.593	1.696		
Rocky Mts.	.071	.096	.519	130	545	1.048	3.956		
Total									

TABLE E-7 (Continued)

Standard Scenario

($3.50 @ 15%)

Year 1990

	Pro-duction (TCF/Yr.)	Production Cumulative (TCF)	Investment ($ Billion)	No. Pro-spects /Yr.	No. Wells /Yr.	Reserves Added (TCF/Yr.)	Reserves Cumula-tive (TCF)	Percent 500 TCF Produced	Percent 500 TCF Added to Reserve
No. Great Plains/Williston	.121	.280	.485	167	942	1.345	8.046		
Eastern	.252	.680	.947	301	1,592	1.739	10.135		
Western	.170	.540	.608	151	737	.826	5.421		
Mid-Continent	.017	.044	.078	28	165	.187	1.018		
Gr. Southwest	.141	.340	1.765	188	688	4.658	13.211		
Southwest	.162	.418	.405	70	356	1.065	6.833		
Rocky Mts.	.473	1.648	.986	222	750	1.750	11.010		
Total									

TABLE E-7 (Continued)

Standard Scenario

($3.50 @ 15%)

Year 1995

	Pro-duction (TCF/Yr.)	Production Cumulative (TCF)	Investment ($ Billion)	No. Pro-spects /Yr.	No. Wells /Yr.	Reserves Added (TCF/Yr.)	Reserves Cumula-tive (TCF)	Percent 500 TCF Produced	Percent 500 TCF Added to Reserve
No. Great Plains/Williston	.429	1.807	.578	212	1,130	1.618	16.030		
Eastern	.599	3.055	.482	155	734	1.122	15.551		
Western	.357	2.059	.320	74	238	.369	7.205		
Mid-Continent	.051	.225	.078	24	149	.190	1.913		
Gr. Southwest	1.338	4.041	2.544	408	2,020	6.618	44.047		
Southwest	.431	2.031	.535	75	351	1.270	12.939		
Rocky Mts.	.962	5.370	1.552	318	1,109	2.585	23.425		
Total									

TABLE E-7 (Continued)

Standard Scenario

($3.50 @ 15%)

Year 2000

	Pro-duction (TCF/Yr.)	Production Cumulative (TCF)	Investment ($ Billion)	No. Pro-spects /Yr.	No. Wells /Yr.	Reserves Added (TCF/Yr.)	Reserves Cumula-tive (TCF)	Percent 500 TCF Produced	Percent 500 TCF Added to Reserve
No. Great Plains/Williston	.746	4.906	.594	223	1,155	1.681	24.437		
Eastern	.717	6.378	.512	163	762	1.201	21.432		
Western	.341	3.766	.320	74	238	.369	9.048		
Mid-Continent	.087	.591	.062	24	127	.161	2.838		
Gr. Southwest	2.882	15.521	2.360	389	1,698	6.242	76.760		
Southwest	.709	5.064	.497	71	284	1.193	19.171		
Rocky Mts.	1.501	11.878	1.531	309	1,085	2.466	36.174		
Total									

TABLE E-8

Standard Scenario

Year 1981 ($5.00 @ 10%)

	Pro-duction (TCF/Yr.)	Production Cumulative (TCF)	Investment ($ Billion)	No. Pro-spects /Yr.	No. Wells /Yr.	Reserves Added (TCF/Yr.)	Reserves Cumula-tive (TCF)	Percent 500 TCF Produced	Percent 500 TCF Added to Reserve
No. Great Plains/Williston			.022	10	68	.077	.077		
Eastern			.230	42	414	.326	.326		
Western			.255	52	441	.373	.373		
Mid-Continent			.021	3	55	.031	.031		
Gr. Southwest			.186	29	213	.362	.362		
Southwest			.049	7	72	.088	.088		
Rocky Mts.			.271	53	279	.499	.499		
Total			1.034	196	1,542	1.756	1.756		

TABLE E-8 (Continued)

Standard Scenario

($5.00 @ 10%)

Year 1985

	Production (TCF/Yr.)	Production Cumulative (TCF)	Investment ($ Billion)	No. Prospects /Yr.	No. Wells /Yr.	Reserves Added (TCF/Yr.)	Reserves Cumulative (TCF)	Percent 500 TCF Produced	Percent 500 TCF Added to Reserve
No. Great Plains/Williston	.003	.004	.255	89	711	.735	1.789		
Eastern	.022	.028	1.013	187	1,864	1.554	4.306		
Western	.029	.037	.438	93	713	.662	2.249		
Mid-Continent	.002	.002	.080	17	238	.140	.468		
Gr. Southwest	.025	.036	.428	55	430	.790	2.782		
Southwest	.008	.010	.502	49	339	.761	1.738		
Rocky Mts.	.076	.103	.849	181	841	1.569	5.417		
Total	.165	.22	3.565	671	5,136	6.238	18.749		

TABLE E-8 (Continued)

Standard Scenario

($5.00 @ 10%)

Year 1990

	Production (TCF/Yr.)	Production Cumulative (TCF)	Investment ($ Billion)	No. Prospects /Yr.	No. Wells /Yr.	Reserves Added (TCF/Yr.)	Reserves Cumulative (TCF)	Percent 500 TCF Produced	Percent 500 TCF Added to Reserve
No. Great Plains/Williston	.127	.293	.529	168	1,019	1.398	8.381		
Eastern	.362	.980	1.737	301	2,829	2.619	15.355		
Western	.231	.711	.878	151	1,200	1.188	7.662		
Mid-Continent	.027	.074	.132	28	318	.249	1.487		
Gr. Southwest	.268	.739	2.909	288	2,680	5.555	18.628		
Southwest	.229	.528	.974	78	630	1.486	8.883		
Rocky Mts.	.599	1.974	1.582	260	1,160	2.371	15.714		
Total	1.843	5.299	8.741	1,274	9,836	14.866	76.11		

TABLE E-8 (Continued)

Standard Scenario

($5.00 @ 10%)

Year 1995

	Pro-duction (TCF/Yr.)	Production Cumulative (TCF)	Investment ($ Billion)	No. Pro-spects /Yr.	No. Wells /Yr.	Reserves Added (TCF/Yr.)	Reserves Cumula-tive (TCF)	Percent 500 TCF Produced	Percent 500 TCF Added to Reserve
No. Great Plains/Williston	0.448	1.888	.703	228	1,407	1.802	16.855		
Eastern	.877	4.436	.939	155	1,174	1.596	23.083		
Western	.510	2.825	.637	74	629	.761	11.333		
Mid-Continent	.071	.335	.112	24	198	.227	2.564		
Gr. Southwest	1.727	5.791	4.295	408	3,262	7.845	55.239		
Southwest	.645	2.973	.688	58	480	1.142	15.369		
Rocky Mts.	1.227	6.828	2.427	325	1,669	3.164	30.316		
Total	5.505	25.076	9.801	1,272	8,819	16.537	157.76		

TABLE E-8 (Continued)

Standard Scenario

($5.00 @ 10%)

Year 2000

	Production (TCF/Yr.)	Production Cumulative (TCF)	Investment ($ Billion)	No. Prospects /Yr.	No. Wells /Yr.	Reserves Added (TCF/Yr.)	Reserves Cumulative (TCF)	Percent 500 TCF Produced	Percent 500 TCF Added to Reserve
No. Great Plains/Williston	.787	5.136	.690	231	1,352	1.793	25.869		
Eastern	1.049	9.305	1.007	157	1,197	1.695	31.494		
Western	.561	5.502	.612	64	571	.701	15.078		
Mid-Continent	.114	.824	.083	24	158	.183	3.662		
Gr. Southwest	3.664	20.413	4.420	404	3,164	7.763	94.383		
Southwest	.868	6.945	.674	57	455	1.122	20.937		
Rocky Mts.	1.849	14.901	2.347	315	1,709	2.878	45.592		
Total	8.892	63.026	9.833	1,252	8,606	16.135	237.05	12.60	47.41

TABLE E-9

Standard Scenario

($5.00 @ 20%)

Year 1981

	Pro-duction (TCF/Yr.)	Production Cumulative (TCF)	Investment ($ Billion)	No. Pro-spects /Yr.	No. Wells /Yr.	Reserves Added (TCF/Yr.)	Reserves Cumula-tive (TCF)	Percent 500 TCF Produced	Percent 500 TCF Added to Reserve
No. Great Plains/Williston			.021	10	67	.076	.076		
Eastern			.213	42	388	.310	.310		
Western			.236	52	401	.354	.354		
Mid-Continent			.017	3	44	.026	.026		
Gr. Southwest			.171	29	182	.342	.342		
Southwest			.044	7	60	.082	.082		
Rocky Mts.			.265	59	269	.494	.494		
Total			.967	202	1,411	1.684	1.684		

TABLE E-9 (Continued)

Standard Scenario

($5.00 @ 20%)

Year 1985

	Production (TCF/Yr.)	Production Cumulative (TCF)	Investment ($ Billion)	No. Prospects /Yr.	No. Wells /Yr.	Reserves Added (TCF/Yr.)	Reserves Cumulative (TCF)	Percent 500 TCF Produced	Percent 500 TCF Added to Reserve
No. Great Plains/Williston	.003	.004	.234	93	664	.717	1.753		
Eastern	.022	.027	.916	187	1,700	1.423	4.058		
Western	.027	.035	.548	93	799	.766	2.277		
Mid-Continent	.001	.002	.069	17	204	.128	.422		
Gr. Southwest	.024	.035	.348	55	364	.746	2.623		
Southwest	.007	.009	.342	48	288	.697	1.591		
Rocky Mts.	.075	.101	.790	176	795	1.546	5.308		
Total	.159	.213	3.247	669	4,814	6.023	18.032		

TABLE E-9 (Continued)

Standard Scenario

($5.00 @ 20%)

Year 1990

	Production (TCF/Yr.)	Production Cumulative (TCF)	Investment ($ Billion)	No. Prospects /Yr.	No. Wells /Yr.	Reserves Added (TCF/Yr.)	Reserves Cumulative (TCF)	Percent 500 TCF Produced	Percent 500 TCF Added to Reserve
No. Great Plains/Williston	.124	.286	.502	167	971	1.366	8.195		
Eastern	.342	.934	1.439	301	2,809	2.634	14.730		
Western	.230	.694	.963	151	1,176	1.250	8.083		
Mid-Continent	.025	.070	.106	28	244	.196	1.294		
Gr. Southwest	.245	.692	2.172	288	3,078	5.545	18.350		
Southwest	.198	.469	.658	78	625	1.460	8.527		
Rocky Mts.	.584	1.938	1.282	253	989	2.143	14.823		
Total	1.748	5.083	7.122	1,266	9,892	14.594	74.002		

TABLE E-9 (Continued)

Standard Scenario

($5.00 @ 20%)

Year 1995

	Pro-duction (TCF/Yr.)	Production Cumulative (TCF)	Investment ($ Billion)	No. Pro-spects /Yr.	No. Wells /Yr.	Reserves Added (TCF/Yr.)	Reserves Cumula-tive (TCF)	Percent 500 TCF Produced	Percent 500 TCF Added to Reserve
No. Great Plains/Williston	.436	1.841	.621	219	1,225	1.709	16.357		
Eastern	.796	4.117	.483	135	1,096	1.275	22.259		
Western	.522	2.866	.517	74	465	.590	10.995		
Mid-Continent	.064	.308	.085	24	148	.168	2.086		
Gr. Southwest	1.529	5.186	3.204	408	3,514	7.786	54.695		
Southwest	.538	2.514	.507	58	475	1.116	14.879		
Rocky Mts.	1.136	6.526	1.735	311	1,253	2.608	27.127		
Total	5.021	23.354	7.152	1,229	8,176	15.252	148.397		

TABLE E-9 (Continued)

Standard Scenario

($5.00 @ 20%)

Year 2000

	Production (TCF/Yr.)	Production Cumulative (TCF)	Investment ($ Billion)	No. Prospects /Yr.	No. Wells /Yr.	Reserves Added (TCF/Yr.)	Reserves Cumulative (TCF)	Percent 500 TCF Produced	Percent 500 TCF Added to Reserve
No. Great Plains/Williston	.762	4.997	.611	223	1,184	1.701	24.926		
Eastern	.862	8.314	.505	138	1,120	1.316	28.705		
Western	.522	5.450	.517	74	465	.590	13.944		
Mid-Continent	.100	.739	.062	24	129	.145	2.906		
Gr. Southwest	3.231	18.084	2.881	389	3,016	7.249	93.089		
Southwest	.736	5.856	.507	58	475	1.115	20.457		
Rocky Mts.	1.617	13.729	1.593	282	1,216	2.262	39.355		
Total	7.830	57.169	6.676	1,188	7,605	14.378	222.382		

TABLE E-10

Standard Scenario

($9.00 @ 15%)

Year 1981

	Pro-duction (TCF/Yr.)	Production Cumulative (TCF)	Investment ($ Billion)	No. Pro-spects /Yr.	No. Wells /Yr.	Reserves Added (TCF/Yr.)	Reserves Cumula-tive (TCF)	Percent 500 TCF Produced	Percent 500 TCF Added to Reserve
No. Great Plains/Williston			.022	10	68	.077	.077		
Eastern			.293	53	579	.429	.429		
Western			.200	32	272	.273	.273		
Mid-Continent			.044	9	128	.075	.075		
Gr. Southwest			.216	26	285	.355	.355		
Southwest			.117	12	154	.182	.182		
Rocky Mts.			.641	115	567	.924	.924		
Total			1.533	257	2,053	2.315	2.315		

TABLE E-10 (Continued)

Standard Scenario

($9.00 @ 15%)

Year 1985

	Production (TCF/Yr.)	Production Cumulative (TCF)	Investment ($ Billion)	No. Prospects /Yr.	No. Wells /Yr.	Reserves Added (TCF/Yr.)	Reserves Cumulative (TCF)	Percent 500 TCF Produced	Percent 500 TCF Added to Reserve
No. Great Plains/Williston	.003	.004	.298	106	817	.837	1.952		
Eastern	.027	.033	1.257	186	2,208	1.776	4.970		
Western	.024	.032	.564	99	820	.769	2.227		
Mid-Continent	.003	.004	.107	22	312	.179	.701		
Gr. Southwest	.027	.037	1.271	123	1,559	2.126	5.402		
Southwest	.017	.022	.705	64	619	1.134	2.771		
Rocky Mts.	.123	.169	1.604	295	1,451	2.232	8.003		
Total	.224	.301	5.809	895	7,786	9.053	26.026		

TABLE E-10 (Continued)

Standard Scenario

($9.00 @ 15%)

Year 1990

	Production (TCF/Yr.)	Production Cumulative (TCF)	Investment ($ Billion)	No. Prospects /Yr.	No. Wells /Yr.	Reserves Added (TCF/Yr.)	Reserves Cumulative (TCF)	Percent 500 TCF Produced	Percent 500 TCF Added to Reserve
No. Great Plains/Williston	.143	.319	.864	276	1,700	2.242	10.976		
Eastern	.391	1.093	1.519	212	2,076	2.282	15.986		
Western	.236	.686	1.004	124	1,056	1.197	7.776		
Mid-Continent	.041	.121	.169	24	271	.276	2.038		
Gr. Southwest	.526	1.333	3.500	279	3,361	6.005	28.537		
Southwest	.232	.616	1.083	86	801	1.838	10.948		
Rocky Mts.	.936	2.951	3.173	401	2,191	3.540	25.519		
Total	2.507	7.119	11.312	1,402	11,456	17.380	101.78		

TABLE E-10 (Continued)

Standard Scenario

($9.00 @ 15%)

Year 1995

	Pro-duction (TCF/Yr.)	Production Cumulative (TCF)	Investment ($ Billion)	No. Pro-spects /Yr.	No. Wells /Yr.	Reserves Added (TCF/Yr.)	Reserves Cumula-tive (TCF)	Percent 500 TCF Produced	Percent 500 TCF Added to Reserve
No. Great Plains/Williston	.621	2.376	1.581	499	3,120	4.005	27.583		
Eastern	.919	4.708	1.205	168	1,429	1.800	25.955		
Western	.551	2.880	.744	83	717	.853	12.592		
Mid-Continent	.097	.498	.131	20	213	.221	3.298		
Gr. Southwest	2.119	8.275	4.297	396	3,523	7.824	68.767		
Southwest	.673	3.108	.751	55	493	1.265	18.888		
Rocky Mts.	1.823	10.503	3.526	405	2,341	3.515	42.595		
Total	6.803	32.348	12.235	1,626	11,836	19.483	199.678		

TABLE E-10 (Continued)

Standard Scenario

Year 2000 ($9.00 @ 15%)

	Production (TCF/Yr.)	Production Cumulative (TCF)	Investment ($ Billion)	No. Prospects /Yr.	No. Wells /Yr.	Reserves Added (TCF/Yr.)	Reserves Cumulative (TCF)	Percent 500 TCF Produced	Percent 500 TCF Added to Reserve
No. Great Plains/Williston	1.387	3.665	1.867	595	3,657	4.800	50.398		
Eastern	1.214	10.293	1.064	150	1,287	1.587	34.009		
Western	.641	5.976	.640	72	641	.751	16.462		
Mid-Continent	.141	1.132	.102	15	162	.168	4.225		
Gr. Southwest	3.855	24.597	2.932	256	2,070	5.418	100.517		
Southwest	.881	7.195	.444	32	284	.740	23.641		
Rocky Mts.	2.406	21.394	3.999	423	2,567	3.789	61.169		
Total	10.525	78.252	11.048	1,543	10,668	17.253	290.42		

10 Percent

TABLE E-11

U.S. Gas Resources Recoverable at Technology and Price,
by Basin Subbasin, and Formation, BCF

Basin	Subbasin	Formation	Base			Advanced		
			$2.50	$5.00	$9.00	$2.50	$5.00	$9.00
Northern Great Plains/ Williston		Mowry	0	937	1105	0	1132	1298
		Mowry, Greenhorn	1957	2021	2022	2214	2221	2221
		Mowry, Carlile	2755	3037	3037	3522	3522	3522
		Mowry, Greenhorn, Carlile	9041	9062	9062	10255	10331	10331
		Mowry, Greenhorn, Carlile, Eagle	10091	10127	10127	12032	12165	12165
		Mowry, Greenhorn, Eagle	3278	4180	4192	4023	5327	5386
		Mowry, Judith River	3618	4082	4097	4782	4836	4836
		Mowry, Carlile, Eagle	5215	5933	5933	5580	7391	7391
		Mowry,Carlile,Eagle,Judith Riv.	7843	9038	9067	11842	11966	11966
		Mowry, Carlile, Judith River	3313	3694	3694	4466	4514	4514
		Greenhorn	1143	1906	1969	1143	2041	2248
		Greenhorn, Carlile	921	998	1000	1179	1188	1188
		Greenhorn, Eagle	2747	3143	3155	3984	4036	4036
		Greenhorn, Carlile, Eagle	2397	2695	2708	2596	3353	3353
		Carlile	0	2862	3116	2266	3805	3945
		Niobrara	6756	6843	6843	7091	7091	7091
		Carlile, Eagle	1411	1623	1629	1589	2156	2186
		Judith River	0	0	1927	0	1480	3051
		Mowry,Grnh.,Car.,Eagle,Jud.Riv.	3392	3681	3681	5872	5934	5934
		Carlile, Niobrara	2260	2518	2525	3434	3481	3481
	Basin Total		68,138	78,380	80,889	87,870	97,970	100,143

TABLE E-11 (Continued)

Basin	Subbasin	Formation	Base $2.50	Base $5.00	Base $9.00	Advanced $2.50	Advanced $5.00	Advanced $9.00
Greater Green River	Lewin Area 1	Almond A	225	286	294	307	307	307
		Ericson, Rock Sprgs., Blair	0	1202	1332	0	2090	2542
		Fort Union	0	729	783	0	1475	1670
		Almond A + Almond B	1092	1092	1092	1156	1156	1156
		Almond A + Ericson, R/S, Blair	1049	1204	1204	1854	1854	1854
		Almond B + Ericson, R/S, Blair	1626	1964	2090	1872	3148	3839
		Lance, Lewis	0	1102	1139	822	1651	1787
	Subbasin Total		3,992	7,579	7,934	6,011	11,681	13,155
	Lewin Area 2 & 3	Almond A	0	1101	1231	1326	1465	1465
		Almond B	0	770	838	0	975	1156
		Ericson, R/S, Blair	0	5046	5493	0	9164	10747
		Fort Union	0	540	578	0	1078	1207
		Almond A + Almond B	1549	1660	1660	1687	1687	1687
		Almond B + Ericson, R/S, Blair	0	3522	3740	3757	5952	7214
		Lance, Lewis	1742	2998	3256	2195	4404	4717
	Subbasin Total		3,291	15,637	16,796	8,965	24,725	28,193
	Washakie	Almond	92	139	154	159	159	159
		Lance, Lewis	0	762	815	0	768	1532
		Lower Mesaverde	0	0	1737	0	0	3176
		Lance, Lewis + Almond	602	651	651	735	735	735
		Lower Mesaverde + Almond	0	1369	1369	1496	1608	1608
	Subbasin Total		694	2,921	4,726	2,390	3,270	7,210
	E/2 Lewin Area 4	Mesaverde	0	1439	1832	0	2670	3942
		Fort Union	0	886	906	0	2070	2070
		Fort Union + Mesaverde	0	385	385	0	858	917
	Subbasin Total		0	2,710	3,123	0	5,598	6,929

TABLE E-11 (Continued)

Basin	Subbasin	Formation	Base $2.50	Base $5.00	Base $9.00	Advanced $2.50	Advanced $5.00	Advanced $9.00
	W/2 Lewin 4, Bridger Lewin 5	Fort Union	0	780	978	0	1695	2489
		Mesaverde Lance	0	0	3425	0	0	6468
		Frontier	0	3439	4349	4349	4737	4921
		Mesaverde, Lance + Frontier	0	1529	1661	1577	1730	1809
		Ft.Union + Mesaverde, Lance	0	876	967	0	1871	2177
	Subbasin Total		0	6,624	11,380	5,926	10,033	17,864
Greater Green River	Sandwash	Lewis 7000	0	752	752	925	925	925
		Lewis 9000	0	721	900	1147	1304	1304
		Mesaverde 9000	0	505	554	0	630	1031
		Mesaverde 11000	0	0	670	0	0	1092
		Lewis 7000 + Mesaverde 9000	0	213	225	303	344	344
		Mesaverde 9000 + Mesaverde 11000	0	148	162	0	311	345
	Subbasin Total		0	2,339	3,263	2,375	3,514	5,041
	Basin Total		7,977	37,810	47,222	25,667	58,821	78,392
Wind River		Lower Fort Union	3355	3709	3709	4563	5115	5115
		Lance 9000	0	860	918	0	1439	1694
		Lance 14000	0	1533	1736	0	2479	3306
		Mesaverde 15000	0	0	0	0	0	0
		Lower Ft.Union + Lance 9000	2789	2971	2971	4324	4800	4800
		Lance 14000 + Mesaverde 15000	0	557	1546	0	0	3179
		Frontier/Muddy	1111	1163	1163	1377	1547	1547
	Basin Total		7,255	10,793	12,043	10,264	15,380	19,641
Uinta		Coaly	1061	1079	1079	1155	1155	1155
		Castlegate	835	979	979	1060	1131	1131
		Coaly + Castlegate	1359	1359	1359	1359	1359	1359
		Wasatch + Coaly	2067	2067	2067	2199	2199	2199
		Wasatch + Barren	1986	1986	1986	2099	2099	2099
		Wasatch	4105	4105	4105	4833	5017	5017
		Barren	1805	1805	1805	2054	2309	2309
	Basin Total		13,218	13,380	13,380	14,759	15,269	15,269

TABLE E-11 (Continued)

Basin	Subbasin	Formation	Base $2.50	Base $5.00	Base $9.00	Advanced $2.50	Advanced $5.00	Advanced $9.00
Piceance		Corcoran Cozette	1763	1865	1884	2216	2294	2294
		Fort Union	0	1077	1130	0	1867	2097
		Mesaverde 8000	8047	9851	10467	10956	15079	17413
		Corcoran Cozette,+ Mesaverde	2526	2665	2665	3509	3509	3509
		Fort Union,+ Mesaverde	947	1029	1072	1214	1874	2304
		Fort Union,+ Corcoran Cozette	475	482	482	596	596	596
		Lower Cretaceous, Jurasic	0	1711	1775	0	2128	2288
	Basin Total		13,758	18,680	19,475	18,491	27,347	30,501
Denver	Area A	Muddy J	0	0	1039	0	4518	5539
	Area B	Muddy J	0	0	297	0	1507	2057
	Basin Total		0	0	1,336	0	6,025	7,596
San Juan		Dakota	463	1494	1812	1494	2020	2213
Val Verde	Ozona	Canyon	0	156	182	370	532	604
Val Verde	Sonora	Canyon	0	633	715	1267	1613	1879
Edwards Lime		Southwest	2142	2319	2423	3098	3171	3171
		Central	0	3820	4375	4056	5353	5477
	Basin Total		2,142	6,139	6,798	7,154	8,524	8,648

TABLE E-11 (Continued)

Basin	Subbasin	Formation	Base $2.50	Base $5.00	Base $9.00	Advanced $2.50	Advanced $5.00	Advanced $9.00
Cotton Valley			6520	6976	7624	8352	12735	12735
		SUMMARY BY BASINS						
Denver			0	0	1336	0	6025	7596
Piceance			13758	18,680	19475	18491	27347	30503
Edwards Lime			2142	6139	6798	7154	8524	8648
San Juan			463	1494	1812	1494	2020	2213
Greater Green River			7977	37810	47222	25,667	58,821	78392
Val Verde - Sonora			0	633	715	1267	1613	1879
Uinta			13218	13380	13380	14759	15269	15269
Val Verde - Ozona			0	156	182	370	532	604
Northern Great Plains/Williston			68138	78380	80889	87870	97970	100143
Wind River			7255	10793	12043	10264	15380	19641
Cotton Valley			6520	6976	7624	8352	12735	12735
TOTAL			119,471	174,441	191,476	175,688	246,236	277,621

20 Percent

TABLE E-12

U.S. Gas Resources Recoverable at Technology and Price,
by Basin Subbasin, and Formation, BCF

Basin	Subbasin	Formation	Base			Advanced		
			$2.50	$5.00	$9.00	$2.50	$5.00	$9.00
Northern Great Plains/ Williston		Mowry	0	0	937	0	0	1287
		Mowry, Greenhorn	0	2021	2022	1998	2221	2221
		Mowry, Carlile	2755	3026	3037	3487	3522	3522
		Mowry, Greenhorn, Carlile	8365	9041	9062	8742	10331	10331
		Mowry, Greenhorn, Carlile, Eagle	8926	10091	10127	9300	11971	12105
		Mowry, Greenhorn, Eagle	0	3728	4180	0	5327	5386
		Mowry, Judith River	0	3618	4092	0	4836	4836
		Mowry, Carlile, Eagle	5215	5917	5933	5580	5580	7391
		Mowry,Carlile,Eagle,Judith Riv.	7843	9038	9067	0	11842	11966
		Mowry, Carlile, Judith River	3313	3682	3694	3568	4466	4514
		Greenhorn	0	1670	1906	0	1670	2216
		Greenhorn, Carlile	0	998	1000	987	1188	1188
		Greenhorn, Eagle	2747	3143	3155	2934	3984	4036
		Greenhorn, Carlile, Eagle	2397	2695	2708	2596	3310	3353
		Carlile	0	2266	2862	0	3196	3945
		Niobrara	0	6843	6843	7091	7091	7091
		Carlile, Eagle	0	1411	1623	0	1589	2156
		Judith River	0	0	1480	0	0	1480
		Mowry,Grnh.,Car.,Eagle,Jud.Riv.	3392	3672	3681	4546	5872	5934
		Carlile, Niobrara	2260	2518	2518	2530	3434	3481
	Basin Total		47,213	75,378	79,927	53,359	91,430	98,439

TABLE E-12 (Continued)

Basin	Subbasin	Formation	Base $2.50	Base $5.00	Base $9.00	Advanced $2.50	Advanced $5.00	Advanced $9.00
Greater Green River	Lewin Area 1	Almond A	127	286	294	291	307	307
		Ericson, Rock Sprgs., Blair	0	0	1202	0	0	2090
		Fort Union	0	729	729	0	966	1475
		Almond A + Almond B	1059	1092	1092	1156	1156	1156
		Almond A + Ericson, R/S, Blair	0	1117	1204	1517	1854	1854
		Almond B + Ericson, R/S, Blair	0	1856	2090	0	2594	3460
		Lance, Lewis	0	992	1102	0	1389	1651
	Subbasin Total		1,186	6,072	7,713	2,964	8,266	11,993
	Lewin Area 2 & 3	Almond A	0	709	1101	655	1326	1465
		Almond B	0	564	770	0	653	1156
		Ericson, R/S, Blair	0	4085	5046	0	6700	9164
		Fort Union	0	412	540	0	711	1078
		Almond A + Almond B	933	1660	1660	1687	1687	1687
		Almond B + Ericson, R/S, Blair	0	3358	3740	0	5061	6784
		Lance, Lewis	0	2699	2998	0	3708	4404
	Subbasin Total		933	13,487	15,855	2,342	19,846	25,738
	Washakie	Almond	0	92	154	139	159	159
		Lance, Lewis	0	623	762	0	0	1323
		Lower Mesaverde	0	0	1041	0	0	3110
		Lance, Lewis + Almond	0	651	651	649	735	735
		Lower Mesaverde + Almond	0	1108	1369	0	1608	1608
	Subbasin Total		0	2,474	3,977	788	2,502	6,935
	E/2 Lewin Area 4	Mesaverde	0	0	1439	0	0	2670
		Fort Union	0	688	886	0	1367	2070
		Fort Union + Mesaverde	0	0	385	0	594	917
	Subbasin Total		0	688	2,710	0	1,961	5,657

TABLE E-12 (Continued)

Basin	Subbasin	Formation	Base $2.50	Base $5.00	Base $9.00	Advanced $2.50	Advanced $5.00	Advanced $9.00
	W/2 Lewin 4, Bridger Lewin 5	Fort Union	0	0	780	0	0	2489
		Mesaverde Lance	0	0	3425	0	0	5004
		Frontier	0	3439	3439	3439	4349	4737
		Mesaverde, Lance + Frontier	0	1237	1622	0	1577	1809
		Ft.Union + Mesaverde, Lance	0	0	876	0	0	2067
	Subbasin Total		0	4,676	10,142	3,439	5,926	16,106
Greater Green River	Sandwash	Lewis 7000	0	674	752	753	925	925
		Lewis 9000	0	0	900	0	1304	1304
		Mesaverde 9000	0	0	505	0	0	848
		Mesaverde 11000	0	0	670	0	0	1092
		Lewis 7000 + Mesaverde 9000	0	205	220	0	320	344
		Mesaverde 9000 + Mesaverde 11000	0	0	153	0	0	311
	Subbasin Total		0	879	3,200	753	2,549	4,824
	Basin Total		2,119	28,276	43,597	10,286	41,050	71,253
Wind River		Lower Fort Union	2877	3709	3709	3677	4563	5115
		Lance 9000	0	769	918	0	1172	1642
		Lance 14000	0	1200	1533	0	0	2495
		Mesaverde 15000	0	0	0	0	0	0
		Lower Ft.Union + Lance 9000	2524	2971	2971	3466	4800	4800
		Lance 14000 + Mesaverde 15000	0	0	1200	0	0	1918
		Frontier/Muddy	0	1111	1163	974	1547	1549
	Basin Total		5,401	9,760	11,494	8,117	12,082	17,519
Uinta		Coaly	1031	1079	1079	1155	1155	1155
		Castlegate	0	835	979	835	1060	1131
		Coaly + Castlegate	1359	1359	1359	1359	1359	1359
		Wasatch + Coaly	2067	2067	2067	2199	2199	2199
		Wasatch + Barren	1986	1986	1986	2099	2099	2099
		Wasatch	4007	4105	4105	4833	5017	5017
		Barren	1672	1805	1805	2054	2309	2309
	Basin Total		12,122	13,236	13,380	14,534	15,198	15,269

TABLE E-12 (Continued)

Basin	Subbasin	Formation	Base $2.50	Base $5.00	Base $9.00	Advanced $2.50	Advanced $5.00	Advanced $9.00
Piceance		Corcoran Cozette	1291	1865	1884	2216	2294	2294
		Fort Union	0	1077	1077	0	1630	1630
		Mesaverde 8000	4729	9851	9851	5579	10956	15079
		Corcoran Cozette,+ Mesaverde	1795	2617	2665	2786	3509	3509
		Fort Union,+ Mesaverde	0	947	1058	0	1619	1981
		Fort Union,+ Corcoran Cozette	446	482	482	577	596	596
		Lower Cretaceous, Jurasic	0	1454	1711	0	1700	2288
	Basin Total		8,261	18,293	18,728	11,158	22,304	27,377
Denver	Area A	Muddy J	0	0	457	0	2443	5539
	Area B	Muddy J	0	0	0	0	694	1507
	Basin Total		0	0	457	0	3,137	7,046
San Juan		Dakota	0	1494	1494	0	1494	2213
Val Verde	Ozona	Canyon	0	0	156	0	532	532
Val Verde	Sonora	Canyon	0	517	688	0	1613	1613
Edwards Lime		Southwest	1643	2391	2423	2958	3098	3171
		Central	0	3820	4311	4056	5353	5477
	Basin Total		1,643	6,211	6,734	7,014	8,451	8,648

TABLE E-12 (Continued)

Basin	Subbasin	Formation	Base $2.50	Base $5.00	Base $9.00	Advanced $2.50	Advanced $5.00	Advanced $9.00
Cotton Valley			5387	6520	6976	7110	9795	12735
		SUMMARY BY BASINS						
Denver			0	0	457	0	3137	7046
Piceance			8261	18293	18729	11158	22304	27377
Edwards Lime			1643	6211	6734	7014	8451	8648
San Juan			0	1494	1494	0	1494	2213
Greater Green River			2119	28,276	43597	10286	41050	71253
Val Verde - Sonora			0	517	688	0	1613	1613
Uinta			12122	13236	13380	14534	15198	15269
Val Verde - Ozona			0	0	156	0	532	532
Northern Great Plains/Williston			47213	75378	79927	53359	91430	98439
Wind River			5401	9760	11494	8117	12082	17519
Cotton Valley			5387	6520	6976	7110	9795	12735
TOTAL			82,146	159,685	183,632	111,578	207,086	262,644

TABLE E-13

Producing Rate Scenario Summary
(Standard Scenario)

ANNUAL BCF GAS PRODUCTION

YR	NGP - WILLISTON	ROCKY MOUNTAINS	OTHER WESTERN	SOUTHWEST APPRAISED	OTHER SOUTHWEST	EASTERN	MID CONTINENT	TOTAL U.S.
1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	0.678	25.871	7.629	2.306	10.587	4.985	0.360	52.417
5	3.234	75.806	27.957	7.597	25.115	22.065	1.541	163.315
6	10.444	155.106	57.880	15.577	50.921	54.466	3.873	348.267
7	23.780	254.924	85.237	40.535	82.640	100.770	8.054	595.939
8	45.937	367.029	117.986	74.835	119.711	165.952	13.170	904.618
9	79.326	481.087	162.851	134.591	174.019	250.806	19.874	1302.552
10	125.688	588.860	220.243	200.966	257.015	350.265	26.858	1769.894
11	185.109	700.959	285.064	275.904	385.937	456.734	34.165	2323.872
12	250.835	822.405	353.312	350.567	601.289	564.661	42.786	2985.854
13	317.986	945.756	418.170	425.806	897.273	678.139	52.120	3734.345
14	380.474	1067.580	480.650	490.987	1246.875	774.178	60.585	4481.324
15	442.978	1190.768	479.186	552.149	1609.781	832.703	71.325	5178.902
16	507.155	1320.788	481.639	606.515	1989.677	854.385	81.340	5841.492
17	574.309	1443.860	487.844	653.142	2357.224	878.735	89.326	6484.434
18	642.267	1562.363	497.560	691.946	2717.799	907.375	97.779	7117.125
19	711.466	1672.386	510.529	726.172	3055.674	939.815	106.135	7722.113
20	776.271	1772.465	524.233	757.291	3372.632	974.683	114.131	8293.699

CUMULATIVE BCF GAS PRODUCTION

YR	NGP - WILLISTON	ROCKY MOUNTAINS	OTHER WESTERN	SOUTHWEST APPRAISED	OTHER SOUTHWEST	EASTERN	MID CONTINENT	TOTAL U.S.
1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	0.678	25.871	7.629	2.306	10.587	4.985	0.360	52.417
5	3.912	101.677	35.586	9.903	35.701	27.050	1.901	215.732
6	14.356	256.783	93.467	25.480	86.623	81.516	5.774	563.999
7	38.137	511.706	178.704	66.015	169.263	182.285	13.828	1159.937
8	84.074	878.736	296.689	140.850	288.973	348.237	26.997	2064.556
9	163.399	1359.823	459.540	275.441	462.992	599.043	46.871	3367.108
10	289.087	1948.683	679.782	476.407	720.008	949.308	73.729	5137.000
11	474.195	2649.642	964.846	752.311	1105.945	1406.042	107.895	7460.871
12	725.030	3472.046	1318.158	1102.878	1707.233	1970.703	150.680	10446.723
13	1042.116	4417.801	1736.329	1528.684	2604.507	2648.842	202.801	14181.066
14	1422.564	5485.379	2196.978	2019.671	3851.382	3423.020	263.386	18662.391
15	1865.562	6676.164	2676.164	2571.819	5461.160	4255.719	334.711	23841.293
16	2372.717	7996.949	3157.803	3178.335	7450.836	5110.102	416.051	29682.785
17	2947.027	9440.809	3645.646	3831.476	9808.059	5988.836	505.377	36167.219
18	3589.314	11003.172	4143.227	4523.422	12525.855	6896.211	603.156	43284.344
19	4300.719	12675.555	4653.754	5249.594	15581.527	7836.023	709.291	51006.457
20	5078.988	14448.016	5177.984	6006.883	18954.156	8810.703	823.422	59300.156

TABLE E-13 (Continued)
Reserve Scenario Summary
(Standard Scenario)

BCF RESERVES ADDED ANNUALLY

YR	NGP - WILLIS.	ROCKY MTN.	OTHER WESTERN	S.W. APPR.	OTHER S.W.	EASTERN	MID CONT.	TOTAL U.S.
1	77.	494.	354.	89.	363.	312.	31.	1719.
2	167.	705.	305.	150.	363.	480.	60.	2350.
3	326.	1107.	374.	200.	564.	713.	105.	3389.
4	477.	1403.	404.	525.	693.	1162.	132.	4796.
5	728.	1557.	630.	741.	783.	1499.	140.	6077.
6	1126.	1653.	810.	1138.	1295.	1775.	158.	7955.
7	1241.	1805.	945.	1404.	1926.	1962.	171.	9455.
8	1426.	1982.	1082.	1456.	2838.	2104.	175.	11063.
9	1358.	2100.	1122.	1542.	4068.	2218.	266.	12740.
10	1387.	2274.	1114.	1477.	5435.	2470.	250.	14406.
11	1505.	2484.	625.	1391.	6405.	1251.	183.	13844.
12	1605.	2590.	693.	1391.	7054.	1415.	214.	14968.
13	1607.	2667.	669.	1305.	7272.	1445.	223.	15487.
14	1624.	2843.	699.	1219.	7491.	1445.	227.	15750.
15	1777.	2961.	712.	1133.	7709.	1445.	227.	15963.
16	1814.	2991.	712.	1133.	7709.	1445.	227.	16030.
17	1812.	2910.	712.	1133.	7709.	1496.	227.	16000.
18	1762.	2876.	712.	1133.	7709.	1536.	227.	15976.
19	1770.	2775.	712.	1133.	7709.	1550.	232.	15880.
20	1770.	2676.	712.	1133.	7172.	1503.	183.	15209.

CUMULATIVE BCF RESERVES ADDED

YR	NGP - WILLIS.	ROCKY MTN.	OTHER WESTERN	S.W. APPR.	OTHER S.W.	EASTERN	MID CONT.	TOTAL U.S.
1	77.	494.	354.	89.	363.	312.	31.	1719.
2	243.	1259.	719.	239.	725.	792.	91.	4069.
3	569.	2366.	1093.	439.	1289.	1505.	196.	7458.
4	1046.	3769.	1497.	965.	1982.	2667.	328.	12253.
5	1774.	5326.	2127.	1705.	2765.	4166.	468.	18330.
6	2900.	6976.	2937.	2843.	4060.	5941.	625.	26285.
7	4142.	8783.	3882.	4247.	5986.	7903.	796.	35740.
8	5568.	10766.	4904.	5704.	8824.	10007.	972.	46803.
9	6925.	12932.	6085.	7246.	12892.	12225.	1238.	59543.
10	8313.	15205.	7199.	8723.	18326.	14695.	1487.	73948.
11	9817.	17689.	7824.	10114.	24731.	15946.	1670.	87792.
12	11422.	20280.	8517.	11505.	31785.	17361.	1885.	102760.
13	13090.	23172.	9206.	12810.	39057.	18806.	2107.	118247.
14	14914.	26017.	9905.	14028.	46548.	20250.	2335.	133997.
15	16691.	28978.	10617.	15161.	54257.	21695.	2562.	149960.
16	18505.	31969.	11329.	16294.	61966.	23139.	2789.	165990.
17	20317.	34879.	12041.	17427.	69675.	24635.	3016.	181990.
18	22099.	37755.	12753.	18560.	77384.	26173.	3243.	197967.
19	23869.	40529.	13465.	19692.	85093.	27723.	3475.	213847.
20	25639.	43205.	14178.	20825.	92265.	29287.	3658.	229056.

TABLE E-13 (Continued)

Well Drilling Committment Scenario Summary

(Standard Scenario)

NO. WELLS ANNUALLY COMMITTED FOR DRILLING

YR	NGP - WILLIS.	ROCKY MTN.	OTHER WESTERN	S.W. APPR.	OTHER S.W.	EASTERN	MID CONT.	TOTAL U.S.
1	67.	269.	401.	72.	213.	391.	55.	1468.
2	154.	390.	411.	94.	213.	583.	102.	1947.
3	298.	587.	418.	111.	300.	863.	181.	2758.
4	477.	736.	455.	228.	379.	1429.	229.	3932.
5	686.	799.	651.	315.	419.	1792.	238.	4900.
6	1044.	812.	825.	452.	776.	2083.	258.	6250.
7	1081.	889.	931.	650.	1148.	2257.	281.	7237.
8	1175.	974.	1066.	601.	1606.	2372.	285.	8079.
9	974.	1061.	1106.	638.	2096.	2488.	372.	8735.
10	996.	1061.	1085.	626.	2621.	2676.	318.	9403.
11	1091.	1222.	524.	589.	2894.	979.	160.	7459.
12	1166.	1269.	562.	589.	3109.	1088.	188.	7971.
13	1219.	1439.	550.	551.	3137.	1110.	194.	8200.
14	1352.	1439.	556.	514.	3165.	1110.	197.	8333.
15	1343.	1509.	571.	476.	3194.	1110.	197.	8400.
16	1361.	1593.	571.	476.	3194.	1110.	197.	8502.
17	1344.	1583.	571.	476.	3194.	1133.	197.	8498.
18	1320.	1604.	571.	476.	3194.	1156.	197.	8517.
19	1295.	1575.	571.	476.	3194.	1170.	200.	8481.
20	1295.	1545.	571.	476.	2696.	1185.	157.	7925.

CUMULATIVE WELLS COMMITTED FOR DRILLING

YR	NGP - WILLIS.	ROCKY MTN.	OTHER WESTERN	S.W. APPR.	OTHER S.W.	EASTERN	MID CONT.	TOTAL U.S.
1	67.	269.	401.	72.	213.	391.	55.	1468.
2	221.	659.	812.	166.	426.	974.	157.	3415.
3	519.	1246.	1230.	277.	726.	1837.	338.	6173.
4	996.	1981.	1685.	505.	1105.	3266.	567.	10105.
5	1682.	2780.	2336.	820.	1524.	5058.	805.	15005.
6	2726.	3592.	3161.	1272.	2300.	7141.	1063.	21255.
7	3807.	4481.	4092.	1922.	3448.	9398.	1344.	28492.
8	4982.	5455.	5158.	2523.	5054.	11770.	1629.	36571.
9	5956.	6516.	6264.	3161.	7150.	14258.	2001.	45306.
10	6952.	7597.	7349.	3787.	9771.	16934.	2319.	54709.
11	8043.	8819.	7873.	4376.	12665.	17913.	2479.	62168.
12	9209.	10088.	8435.	4965.	15774.	19001.	2667.	70139.
13	10428.	11527.	8985.	5516.	18911.	20111.	2861.	78339.
14	11780.	12966.	9541.	6030.	22076.	21221.	3058.	86672.
15	13123.	14475.	10112.	6506.	25270.	22331.	3255.	95072.
16	14484.	16068.	10683.	6982.	28464.	23441.	3452.	103574.
17	15828.	17651.	11254.	7458.	31658.	24574.	3649.	112072.
18	17148.	19255.	11825.	7934.	34852.	25729.	3846.	120589.
19	18443.	20830.	12396.	8410.	38046.	26899.	4046.	129070.
20	19738.	22375.	12967.	8886.	40742.	28084.	4203.	136995.

TABLE E-13 (Continued)

Producing Rate Per Committed Well Scenario Summary
(Standard Scenario)

ANNUAL BCF GAS PRODUCTION PER COMMITTED WELL

YR	NGP - WILLIS.	ROCKY MTN.	OTHER WESTERN	S.W. APPR.	OTHER S.W.	EASTERN	MID CONT.	TOTAL U.S.
1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	0.001	0.035	0.017	0.010	0.028	0.003	0.002	0.013
5	0.005	0.095	0.043	0.024	0.060	0.012	0.006	0.033
6	0.010	0.191	0.070	0.034	0.066	0.026	0.015	0.056
7	0.022	0.287	0.092	0.062	0.072	0.045	0.029	0.082
8	0.039	0.377	0.111	0.125	0.075	0.070	0.046	0.112
9	0.081	0.453	0.147	0.211	0.083	0.101	0.053	0.149
10	0.126	0.545	0.203	0.321	0.098	0.131	0.084	0.188
11	0.170	0.574	0.544	0.468	0.133	0.467	0.214	0.312
12	0.215	0.648	0.629	0.595	0.193	0.519	0.228	0.375
13	0.260	0.657	0.760	0.773	0.286	0.611	0.269	0.455
14	0.281	0.742	0.829	0.955	0.394	0.697	0.308	0.538
15	0.330	0.789	0.839	1.160	0.504	0.750	0.362	0.617
16	0.373	0.829	0.844	1.274	0.623	0.770	0.413	0.687
17	0.427	0.912	0.854	1.372	0.738	0.776	0.453	0.763
18	0.487	0.974	0.871	1.454	0.851	0.786	0.496	0.836
19	0.549	1.062	0.894	1.526	0.957	0.803	0.531	0.911
20	0.601	1.147	0.918	1.591	1.251	0.823	0.727	1.047

CUM. BCF GAS PROD. PER COMMITTED WELL

YR	NGP - WILLIS.	ROCKY MTN.	OTHER WESTERN	S.W. APPR.	OTHER S.W.	EASTERN	MID CONT.	TOTAL U.S.
1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	0.001	0.013	0.005	0.005	0.010	0.002	0.001	0.005
5	0.002	0.037	0.015	0.012	0.023	0.005	0.002	0.014
6	0.005	0.071	0.030	0.020	0.038	0.011	0.005	0.027
7	0.010	0.114	0.044	0.034	0.049	0.019	0.010	0.041
8	0.017	0.161	0.058	0.056	0.057	0.030	0.017	0.056
9	0.027	0.209	0.073	0.087	0.065	0.042	0.023	0.074
10	0.042	0.257	0.092	0.126	0.074	0.056	0.032	0.094
11	0.059	0.300	0.123	0.172	0.087	0.078	0.044	0.120
12	0.079	0.344	0.156	0.222	0.108	0.104	0.056	0.149
13	0.100	0.383	0.193	0.277	0.138	0.132	0.071	0.181
14	0.121	0.423	0.230	0.335	0.174	0.161	0.086	0.215
15	0.142	0.461	0.265	0.395	0.216	0.191	0.103	0.251
16	0.164	0.498	0.296	0.455	0.262	0.218	0.121	0.287
17	0.186	0.535	0.324	0.514	0.310	0.244	0.138	0.323
18	0.209	0.571	0.350	0.570	0.359	0.268	0.157	0.359
19	0.233	0.609	0.375	0.624	0.410	0.291	0.175	0.395
20	0.257	0.646	0.399	0.676	0.465	0.314	0.196	0.433

TABLE E-13 (Continued)

Reserves Per Committed Well Scenario Summary

(Standard Scenario)

ANNUAL BCF RESERVES ADDED PER COMMITTED WELL

YR	NGP - WILLIS.	ROCKY MTN.	OTHER WESTERN	S.W. APPR.	OTHER S.W.	EASTERN	MID CONT.	TOTAL U.S.
1	1.145	1.837	0.883	1.231	1.702	0.798	0.562	1.171
2	1.081	1.962	0.888	1.600	1.702	0.823	0.589	1.207
3	1.095	1.886	0.895	1.805	1.878	0.826	0.578	1.229
4	1.000	1.909	0.888	2.303	1.828	0.813	0.576	1.220
5	1.061	1.948	0.967	2.352	1.869	0.836	0.589	1.240
6	1.079	2.035	0.982	2.517	1.669	0.852	0.610	1.273
7	1.148	2.030	1.015	2.160	1.678	0.869	0.609	1.306
8	1.214	2.035	1.015	2.423	1.767	0.887	0.615	1.369
9	1.394	2.041	1.014	2.418	1.941	0.891	0.715	1.458
10	1.393	2.103	1.027	2.359	2.073	0.923	0.785	1.532
11	1.379	2.033	1.192	2.361	2.213	1.278	1.144	1.856
12	1.377	2.046	1.233	2.361	2.269	1.300	1.140	1.878
13	1.368	2.006	1.252	2.368	2.318	1.301	1.149	1.889
14	1.349	1.977	1.258	2.371	2.367	1.301	1.153	1.890
15	1.323	1.962	1.247	2.380	2.414	1.301	1.153	1.900
16	1.333	1.877	1.247	2.380	2.414	1.301	1.153	1.885
17	1.348	1.839	1.247	2.380	2.414	1.321	1.153	1.883
18	1.350	1.793	1.247	2.380	2.414	1.331	1.153	1.876
19	1.367	1.762	1.247	2.380	2.414	1.325	1.157	1.872
20	1.367	1.732	1.247	2.380	2.660	1.319	1.165	1.919

CUM. RESERVES ADDED PER COMMITTED WELL (BCF)

YR	NGP - WILLIS.	ROCKY MTN.	OTHER WESTERN	S.W. APPR.	OTHER S.W.	EASTERN	MID CONT.	TOTAL U.S.
1	1.145	1.837	0.883	1.231	1.702	0.798	0.562	1.171
2	1.100	1.911	0.885	1.440	1.702	0.813	0.580	1.191
3	1.097	1.899	0.889	1.586	1.775	0.819	0.579	1.208
4	1.050	1.903	0.888	1.910	1.793	0.817	0.578	1.213
5	1.055	1.916	0.910	2.080	1.814	0.824	0.581	1.222
6	1.064	1.943	0.929	2.235	1.765	0.832	0.588	1.237
7	1.088	1.960	0.949	2.210	1.736	0.841	0.592	1.254
8	1.118	1.974	0.962	2.261	1.746	0.850	0.596	1.280
9	1.163	1.985	0.971	2.292	1.803	0.857	0.619	1.314
10	1.196	2.001	0.980	2.303	1.876	0.868	0.641	1.352
11	1.221	2.006	0.994	2.311	1.953	0.890	0.674	1.412
12	1.240	2.011	1.010	2.317	2.015	0.914	0.707	1.465
13	1.255	2.010	1.025	2.322	2.065	0.935	0.737	1.509
14	1.266	2.007	1.038	2.326	2.109	0.954	0.763	1.546
15	1.272	2.002	1.050	2.330	2.147	0.972	0.787	1.577
16	1.278	1.990	1.060	2.334	2.177	0.987	0.808	1.603
17	1.284	1.976	1.070	2.337	2.201	1.002	0.827	1.624
18	1.289	1.961	1.079	2.339	2.220	1.017	0.843	1.642
19	1.294	1.946	1.086	2.342	2.237	1.031	0.859	1.657
20	1.299	1.931	1.093	2.344	2.265	1.043	0.870	1.672

TABLE E-13 (Continued)
Production Rate vs. Remaining Reserves
(Standard Scenario)

REMAINING BCF RESERVES = CUM. RES - CUM. PROD

YR	NGP - WILLISTON	ROCKY MOUNTAINS	OTHER WESTERN	SOUTHWEST APPRAISED	OTHER SOUTHWEST	EASTERN	MID CONTINENT	TOTAL U.S.
1	76.700	494.200	353.900	88.600	362.600	312.200	30.900	1719.100
2	243.200	1259.200	719.000	239.000	725.200	792.100	91.000	4068.699
3	569.400	2366.400	1093.000	439.400	1288.700	1505.000	195.700	7457.598
4	1045.521	3743.529	1489.371	962.194	1971.113	2662.115	327.140	12200.977
5	1770.087	5224.219	2091.214	1695.397	2729.199	4138.547	465.798	18114.457
6	2886.043	6721.711	2843.533	2817.620	3973.177	5859.281	619.426	25720.789
7	4103.363	8271.785	3703.196	4181.281	5816.734	7720.910	782.472	34579.746
8	5483.426	9886.957	4666.809	5562.844	8534.523	9659.156	944.602	44738.316
9	6761.797	11571.770	5625.754	6970.652	12428.504	11626.246	1190.828	56175.559
10	8023.508	13256.508	6519.609	8246.582	17605.992	13745.684	1413.470	68811.312
11	9343.000	15039.645	6859.344	9361.578	23625.156	14540.047	1562.405	80331.125
12	10697.262	16813.641	7199.031	10401.910	30077.566	15390.086	1733.919	92313.312
13	12047.477	18754.387	7469.457	11281.000	36452.395	16156.543	1904.698	104065.812
14	13491.301	20532.008	7708.008	12008.812	42696.121	16826.965	2071.313	115334.375
15	14825.223	22302.020	7940.922	12589.461	48795.344	17438.863	2227.188	126118.875
16	16132.066	23971.734	8171.379	13115.742	54514.668	18029.078	2373.049	136307.562
17	17370.055	25438.273	8395.633	13595.398	59866.441	18646.543	2510.922	145823.062
18	18509.766	26751.410	8610.152	14036.250	64857.645	19276.766	2640.343	154682.125
19	19568.363	27853.625	8811.723	14442.875	69510.937	19887.352	2765.708	162840.375
20	20560.094	28757.461	8999.590	14818.383	73310.375	20475.969	2834.477	169756.125

PERCENT BCF ANNUAL PROD / BCF REMAIN RES

YR	NGP - WILLIS.	ROCKY MTN.	OTHER WESTERN	S.W. APPR.	OTHER S.W.	EASTERN	MID CONT.	TOTAL U.S.
1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	0.065	0.691	0.512	0.240	0.537	0.187	0.110	0.430
5	0.183	1.451	1.337	0.448	0.920	0.533	0.331	0.902
6	0.362	2.368	2.036	0.553	1.282	0.930	0.625	1.354
7	0.580	3.082	2.302	0.969	1.421	1.305	1.029	1.723
8	0.838	3.712	2.528	1.345	1.403	1.718	1.394	2.022
9	1.173	4.157	2.895	1.931	1.400	2.157	1.669	2.319
10	1.566	4.442	3.378	2.437	1.460	2.548	1.900	2.572
11	1.981	4.661	4.156	2.947	1.634	3.141	2.187	2.893
12	2.345	4.891	4.908	3.370	1.999	3.669	2.468	3.234
13	2.632	5.043	5.598	3.775	2.461	4.197	2.736	3.588
14	2.820	5.200	5.976	4.089	2.920	4.601	2.925	3.886
15	2.988	5.339	6.034	4.386	3.299	4.775	3.202	4.106
16	3.144	5.510	5.894	4.624	3.650	4.739	3.428	4.286
17	3.306	5.676	5.811	4.804	3.937	4.713	3.558	4.447
18	3.470	5.840	5.779	4.930	4.190	4.707	3.703	4.601
19	3.635	6.004	5.794	5.028	4.396	4.726	3.838	4.742
20	3.785	6.163	5.825	5.110	4.600	4.760	4.027	4.886

TABLE E-13 (Continued)
Investment Committment Scenario Summary
(Standard Scenario)

MM-DOLLARS INVESTMENT COMMITTED ANNUALLY

YR	NGP - WILLIS.	ROCKY MTN.	OTHER WESTERN	S.W. APPR.	OTHER S.W.	EASTERN	MID CONT.	TOTAL U.S.
1	21.	266.	236.	49.	186.	215.	21.	993.
2	47.	395.	249.	78.	186.	326.	38.	1319.
3	97.	562.	255.	103.	288.	473.	65.	1842.
4	155.	710.	286.	257.	349.	747.	77.	2580.
5	243.	797.	401.	354.	387.	953.	80.	3214.
6	390.	862.	552.	521.	654.	1146.	85.	4210.
7	436.	1007.	642.	658.	968.	1262.	92.	5064.
8	508.	1177.	765.	680.	1391.	1356.	93.	5969.
9	505.	1344.	802.	718.	1895.	1449.	148.	6861.
10	518.	1441.	785.	694.	2443.	1565.	132.	7578.
11	563.	1718.	509.	656.	2845.	682.	91.	7063.
12	601.	1803.	564.	656.	3144.	753.	107.	7628.
13	622.	2065.	554.	619.	3254.	763.	110.	7987.
14	687.	2069.	561.	581.	3365.	763.	111.	8137.
15	674.	2184.	571.	543.	3475.	763.	111.	8322.
16	688.	2241.	571.	543.	3475.	763.	111.	8393.
17	686.	2215.	571.	543.	3475.	786.	111.	8387.
18	673.	2210.	571.	543.	3475.	803.	111.	8387.
19	663.	2163.	571.	543.	3475.	814.	113.	8342.
20	663.	2113.	571.	543.	3153.	824.	82.	7949.

CUM. MM-DOLLARS INVESTMENT COMMITTED

YR	NGP - WILLIS.	ROCKY MTN.	OTHER WESTERN	S.W. APPR.	OTHER S.W.	EASTERN	MID CONT.	TOTAL U.S.
1	21.	266.	236.	49.	186.	215.	21.	993.
2	68.	661.	485.	127.	372.	540.	59.	2312.
3	165.	1223.	739.	230.	660.	1013.	124.	4154.
4	320.	1933.	1026.	487.	1009.	1760.	201.	6734.
5	562.	2729.	1427.	841.	1396.	2712.	281.	9949.
6	953.	3591.	1978.	1362.	2051.	3858.	366.	14159.
7	1389.	4598.	2620.	2020.	3018.	5120.	458.	19222.
8	1897.	5774.	3385.	2699.	4409.	6475.	550.	25191.
9	2402.	7118.	4187.	3417.	6305.	7924.	698.	32052.
10	2920.	8559.	4972.	4111.	8748.	9490.	830.	39630.
11	3484.	10277.	5481.	4767.	11593.	10171.	920.	46693.
12	4085.	12080.	6044.	5423.	14736.	10924.	1028.	54321.
13	4707.	14146.	6598.	6041.	17991.	11688.	1138.	62309.
14	5394.	16215.	7159.	6622.	21355.	12451.	1249.	70445.
15	6068.	18399.	7729.	7166.	24831.	13214.	1360.	78767.
16	6757.	20640.	8300.	7709.	28306.	13977.	1471.	87161.
17	7442.	22855.	8871.	8252.	31782.	14763.	1582.	95547.
18	8115.	25065.	9442.	8796.	35257.	15566.	1694.	103935.
19	8779.	27228.	10012.	9339.	38732.	16380.	1806.	112276.
20	9442.	29341.	10583.	9882.	41885.	17204.	1888.	120225.

TABLE E-13 (Continued)
Cash Flow Scenario Summary
(Standard Scenario)

ANNUAL CASH FLOW MM-DOLLARS

YR	NGP - WILLISTON	ROCKY MOUNTAINS	OTHER WESTERN	SOUTHWEST APPRAISED	OTHER SOUTHWEST	EASTERN	MID CONTINENT	TOTAL U.S.
1	-0.446	-0.760	-0.677	-0.291	-1.420	-0.837	-0.056	-4.488
2	-3.143	-11.420	-9.557	-2.056	-7.039	-8.797	-0.975	-42.986
3	-8.491	-54.767	-25.836	-9.545	-38.397	-27.148	-2.525	-166.710
4	-14.742	-34.396	-23.413	-18.842	-41.731	-39.665	-6.848	-179.638
5	-24.833	0.794	-29.652	-25.460	-48.520	-74.274	-10.973	-212.918
6	-32.774	117.382	11.146	-49.332	-20.247	-71.276	-14.374	-59.475
7	-43.141	272.837	47.695	-34.473	19.066	-53.779	-12.830	195.376
8	-39.516	459.060	77.851	-12.886	55.641	-9.646	-9.923	520.578
9	-12.827	661.899	128.695	82.623	92.530	74.815	-1.209	1026.525
10	28.559	854.371	205.278	182.665	139.003	197.753	8.125	1615.754
11	106.800	1037.284	313.561	319.727	211.512	360.997	17.898	2367.779
12	203.095	1250.009	439.842	468.370	430.747	560.112	28.454	3380.628
13	315.443	1464.270	587.633	629.660	826.927	802.785	42.415	4669.129
14	427.469	1677.899	697.684	769.525	1390.055	998.229	63.222	6024.078
15	534.343	1865.774	788.248	906.205	2031.588	1278.847	86.140	7491.137
16	639.912	2108.427	801.776	1033.428	2746.702	1375.129	106.667	8812.031
17	761.025	2334.209	817.924	1145.535	3449.004	1450.262	121.839	10079.793
18	873.161	2573.492	833.821	1239.250	4179.500	1511.053	138.054	11348.320
19	999.138	2799.402	856.662	1320.881	4879.141	1576.226	154.318	12585.758
20	1124.503	3012.738	881.819	1394.186	5547.812	1646.696	170.066	13777.809

CUMULATIVE MM-DOLLARS CASH FLOW

YR	NGP - WILLISTON	ROCKY MOUNTAINS	OTHER WESTERN	SOUTHWEST APPRAISED	OTHER SOUTHWEST	EASTERN	MID CONTINENT	TOTAL U.S.
1	-0.446	-0.760	-0.677	-0.291	-1.420	-0.837	-0.056	-4.488
2	-3.588	-12.180	-10.234	-2.347	-8.459	-9.635	-1.031	-47.474
3	-12.079	-66.947	-36.071	-11.892	-46.856	-36.783	-3.556	-214.184
4	-26.821	-101.344	-59.483	-30.734	-88.587	-76.448	-10.405	-393.822
5	-51.654	-100.550	-89.135	-56.195	-137.107	-150.723	-21.378	-606.740
6	-84.428	16.832	-77.989	-105.527	-157.353	-221.999	-35.752	-666.215
7	-127.569	289.669	-30.294	-139.999	-138.287	-275.777	-48.581	-470.839
8	-167.085	748.729	47.557	-152.888	-82.646	-285.424	-58.504	49.738
9	-179.912	1410.628	176.252	-70.265	9.883	-210.609	-59.713	1076.264
10	-151.353	2264.999	381.530	112.400	148.886	-12.855	-51.589	2692.017
11	-44.553	3302.283	695.090	432.128	360.399	348.142	-33.691	5059.793
12	158.542	4552.289	1134.933	900.498	791.146	908.254	-5.238	8440.416
13	473.985	6016.559	1722.565	1530.158	1618.073	1711.038	37.177	13109.547
14	901.454	7694.457	2420.249	2299.684	3008.128	2709.267	100.399	19133.625
15	1435.797	9560.230	3208.496	3205.889	5039.715	3988.114	186.539	26624.762
16	2075.709	11668.656	4010.272	4239.316	7786.414	5363.242	293.206	35436.793
17	2836.735	14002.863	4828.195	5384.852	11235.418	6813.504	415.045	45516.586
18	3709.896	16576.352	5662.016	6624.098	15414.918	8324.555	553.099	56864.906
19	4709.031	19375.750	6518.676	7944.977	20294.059	9900.777	707.416	69450.625
20	5833.531	22388.484	7400.492	9339.160	25841.871	11547.473	877.482	83228.375

TABLE E-13 (Continued)
Investment Per Committed Wells Scenario Summary
(Standard Scenario)

ANNUAL MM-DOLLARS PER WELL (COMMITTED)

YR	NGP - WILLIS.	ROCKY MTN.	OTHER WESTERN	S.W. APPR.	OTHER S.W.	EASTERN	MID CONT.	TOTAL U.S.
1	0.310	0.987	0.588	0.681	0.873	0.549	0.382	0.676
2	0.305	1.014	0.606	0.834	0.873	0.558	0.371	0.677
3	0.326	0.957	0.609	0.924	0.961	0.548	0.359	0.668
4	0.325	0.966	0.629	1.127	0.920	0.522	0.337	0.656
5	0.354	0.997	0.616	1.123	0.924	0.532	0.335	0.656
6	0.374	1.061	0.668	1.152	0.843	0.550	0.331	0.674
7	0.404	1.132	0.689	1.012	0.843	0.559	0.326	0.700
8	0.432	1.208	0.718	1.131	0.866	0.571	0.326	0.739
9	0.518	1.267	0.725	1.125	0.904	0.582	0.397	0.785
10	0.520	1.333	0.723	1.108	0.932	0.585	0.415	0.806
11	0.516	1.406	0.971	1.114	0.983	0.696	0.566	0.947
12	0.516	1.421	1.003	1.114	1.011	0.692	0.570	0.957
13	0.510	1.435	1.008	1.123	1.037	0.688	0.566	0.974
14	0.508	1.438	1.008	1.130	1.063	0.688	0.564	0.976
15	0.502	1.447	0.999	1.141	1.088	0.688	0.564	0.991
16	0.506	1.407	0.999	1.141	1.088	0.688	0.564	0.987
17	0.510	1.399	0.999	1.141	1.088	0.693	0.564	0.987
18	0.510	1.378	0.999	1.141	1.088	0.696	0.564	0.985
19	0.512	1.373	0.999	1.141	1.088	0.695	0.563	0.984
20	0.512	1.368	0.999	1.141	1.169	0.695	0.523	1.003

CUM. MM-DOLLARS PER WELL (COMMITTED)

YR	NGP - WILLIS.	ROCKY MTN.	OTHER WESTERN	S.W. APPR.	OTHER S.W.	EASTERN	MID CONT.	TOTAL U.S.
1	0.310	0.987	0.588	0.681	0.873	0.549	0.382	0.676
2	0.306	1.003	0.597	0.767	0.873	0.555	0.375	0.677
3	0.318	0.981	0.601	0.830	0.910	0.551	0.366	0.673
4	0.321	0.976	0.609	0.964	0.913	0.539	0.354	0.666
5	0.334	0.982	0.611	1.025	0.916	0.536	0.349	0.663
6	0.349	1.000	0.626	1.070	0.892	0.540	0.344	0.666
7	0.365	1.026	0.640	1.051	0.875	0.545	0.340	0.675
8	0.381	1.058	0.656	1.070	0.872	0.550	0.338	0.689
9	0.403	1.092	0.668	1.081	0.882	0.556	0.349	0.707
10	0.420	1.127	0.677	1.085	0.895	0.560	0.358	0.724
11	0.433	1.165	0.696	1.089	0.915	0.568	0.371	0.751
12	0.444	1.198	0.717	1.092	0.934	0.575	0.385	0.774
13	0.451	1.227	0.734	1.095	0.951	0.581	0.398	0.795
14	0.458	1.251	0.750	1.098	0.967	0.587	0.408	0.813
15	0.462	1.271	0.764	1.101	0.983	0.592	0.418	0.829
16	0.467	1.285	0.777	1.104	0.994	0.596	0.426	0.842
17	0.470	1.295	0.788	1.107	1.004	0.601	0.434	0.853
18	0.473	1.302	0.798	1.109	1.012	0.605	0.440	0.862
19	0.476	1.307	0.808	1.110	1.018	0.609	0.446	0.870
20	0.478	1.311	0.816	1.112	1.028	0.613	0.449	0.878

TABLE E-13 (Continued)

Investment/Reserves Ratio Scenario Summary

(Standard Scenario)

ANNUAL MM-DOLLARS COMMITTED PER BCF RESERVES

YR	NGP - WILLIS.	ROCKY MTN.	OTHER WESTERN	S.W. APPR.	OTHER S.W.	EASTERN	MID CONT.	TOTAL U.S.
1	0.271	0.537	0.667	0.553	0.513	0.688	0.680	0.578
2	0.282	0.517	0.682	0.521	0.513	0.678	0.629	0.561
3	0.298	0.507	0.681	0.512	0.512	0.663	0.620	0.544
4	0.325	0.506	0.708	0.489	0.503	0.642	0.586	0.538
5	0.334	0.512	0.637	0.477	0.494	0.636	0.569	0.529
6	0.347	0.521	0.681	0.458	0.505	0.646	0.542	0.529
7	0.352	0.558	0.679	0.469	0.502	0.643	0.535	0.536
8	0.356	0.594	0.708	0.467	0.490	0.644	0.529	0.540
9	0.372	0.621	0.715	0.465	0.466	0.653	0.555	0.539
10	0.374	0.634	0.704	0.470	0.450	0.634	0.529	0.526
11	0.374	0.692	0.814	0.472	0.444	0.545	0.495	0.510
12	0.375	0.694	0.813	0.472	0.446	0.532	0.500	0.510
13	0.373	0.716	0.805	0.474	0.447	0.528	0.493	0.516
14	0.377	0.727	0.802	0.477	0.449	0.528	0.489	0.517
15	0.379	0.738	0.801	0.480	0.451	0.528	0.489	0.521
16	0.379	0.749	0.801	0.480	0.451	0.528	0.489	0.524
17	0.378	0.761	0.801	0.480	0.451	0.525	0.489	0.524
18	0.378	0.769	0.801	0.480	0.451	0.523	0.489	0.525
19	0.375	0.779	0.801	0.480	0.451	0.525	0.486	0.525
20	0.375	0.790	0.801	0.480	0.440	0.527	0.449	0.523

CUM. MM-DOLLARS COMMITTED PER BCF RESERVES

YR	NGP - WILLIS.	ROCKY MTN.	OTHER WESTERN	S.W. APPR.	OTHER S.W.	EASTERN	MID CONT.	TOTAL U.S.
1	0.271	0.537	0.667	0.553	0.513	0.688	0.680	0.578
2	0.278	0.525	0.674	0.533	0.513	0.682	0.646	0.568
3	0.289	0.517	0.677	0.523	0.512	0.673	0.632	0.557
4	0.305	0.513	0.685	0.505	0.509	0.660	0.613	0.550
5	0.317	0.512	0.671	0.493	0.505	0.651	0.600	0.543
6	0.328	0.515	0.674	0.479	0.505	0.649	0.586	0.539
7	0.335	0.523	0.675	0.475	0.504	0.648	0.575	0.538
8	0.341	0.536	0.682	0.473	0.500	0.647	0.566	0.538
9	0.347	0.550	0.688	0.472	0.489	0.648	0.564	0.538
10	0.351	0.563	0.691	0.471	0.477	0.646	0.558	0.536
11	0.355	0.581	0.700	0.471	0.469	0.638	0.551	0.532
12	0.358	0.596	0.710	0.471	0.464	0.629	0.545	0.529
13	0.360	0.610	0.717	0.472	0.461	0.622	0.540	0.527
14	0.362	0.623	0.723	0.472	0.459	0.615	0.535	0.526
15	0.364	0.635	0.728	0.473	0.458	0.609	0.531	0.525
16	0.365	0.646	0.733	0.473	0.457	0.604	0.527	0.525
17	0.366	0.655	0.737	0.474	0.456	0.599	0.525	0.525
18	0.367	0.664	0.740	0.474	0.456	0.595	0.522	0.525
19	0.368	0.672	0.744	0.474	0.455	0.591	0.520	0.525
20	0.368	0.679	0.746	0.475	0.454	0.587	0.516	0.525

TABLE E-14

Producing Rate Scenario Summary
(Half-Standard Scenario)

ANNUAL BCF GAS PRODUCTION

YR	NGP - WILLISTON	ROCKY MOUNTAINS	OTHER WESTERN	SOUTHWEST APPRAISED	OTHER SOUTHWEST	EASTERN	MID CONTINENT	TOTAL U.S.
1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	0.228	10.541	3.273	1.588	5.016	2.190	0.360	23.197
5	1.296	35.399	13.413	4.299	12.505	10.535	1.127	78.575
6	4.307	75.603	27.515	8.189	25.894	27.157	2.236	170.900
7	10.554	129.475	42.270	18.908	41.751	51.035	3.705	297.697
8	21.227	190.034	59.119	36.977	58.841	83.744	6.613	456.555
9	37.351	251.203	81.493	66.801	85.499	125.854	9.621	657.820
10	60.084	313.958	109.842	100.625	129.777	176.002	13.007	903.293
11	89.923	375.650	142.596	137.756	195.035	229.561	16.753	1187.272
12	123.842	437.350	177.051	176.308	302.915	283.433	21.312	1522.212
13	157.919	495.789	209.178	211.917	450.295	339.430	26.218	1890.747
14	188.183	546.860	230.640	246.865	624.219	387.272	31.234	2255.274
15	217.352	597.531	239.735	275.003	807.115	416.159	37.262	2590.157
16	247.961	645.655	238.634	304.296	995.694	427.207	41.183	2900.631
17	280.104	695.196	239.771	325.172	1178.719	438.962	46.443	3204.367
18	312.924	746.074	244.131	346.689	1358.025	453.615	49.286	3510.744
19	347.028	799.473	251.803	361.699	1528.302	469.436	54.831	3812.571
20	381.750	852.206	260.557	379.414	1685.350	487.536	57.366	4104.176

CUMULATIVE BCF GAS PRODUCTION

YR	NGP - WILLISTON	ROCKY MOUNTAINS	OTHER WESTERN	SOUTHWEST APPRAISED	OTHER SOUTHWEST	EASTERN	MID CONTINENT	TOTAL U.S.
1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	0.228	10.541	3.273	1.588	5.016	2.190	0.360	23.197
5	1.524	45.940	16.687	5.887	17.521	12.725	1.487	101.772
6	5.831	121.543	44.202	14.076	43.415	39.882	3.723	272.671
7	16.384	251.018	86.471	32.983	85.166	90.917	7.428	570.368
8	37.612	441.052	145.590	69.961	144.007	174.661	14.041	1026.923
9	74.963	692.255	227.083	136.762	229.506	300.514	23.662	1684.744
10	135.046	1006.213	336.924	237.387	359.282	476.516	36.669	2588.037
11	224.969	1381.864	479.520	375.142	554.317	706.077	53.422	3775.309
12	348.812	1819.214	656.571	551.451	857.232	989.510	74.734	5297.520
13	506.731	2315.003	865.748	763.368	1307.527	1328.940	100.952	7188.266
14	694.914	2861.863	1096.388	1010.233	1931.746	1716.213	132.186	9443.539
15	912.265	3459.395	1336.123	1285.237	2738.861	2132.372	169.448	12033.695
16	1160.227	4105.047	1574.758	1589.532	3734.555	2559.579	210.632	14934.324
17	1440.331	4800.242	1814.529	1914.704	4913.270	2998.542	257.074	18138.687
18	1753.255	5546.312	2058.659	2261.394	6271.293	3452.156	306.360	21649.430
19	2100.283	6345.785	2310.462	2623.093	7799.594	3921.592	361.190	25462.000
20	2482.032	7197.988	2571.020	3002.506	9484.941	4409.125	418.557	29566.176

TABLE E-14 (Continued)

Reserve Scenario Summary

(Half-Standard Scenario)

BCF RESERVES ADDED ANNUALLY

YR	NGP - WILLIS.	ROCKY MTN.	OTHER WESTERN	S.W. APPR.	OTHER S.W.	EASTERN	MID CONT.	TOTAL U.S.
1	25.	202.	152.	54.	174.	140.	20.	768.
2	80.	369.	199.	72.	188.	254.	33.	1195.
3	150.	559.	175.	102.	280.	376.	51.	1692.
4	224.	775.	228.	223.	374.	583.	51.	2457.
5	365.	860.	315.	388.	372.	738.	71.	3109.
6	533.	905.	395.	578.	626.	882.	75.	3994.
7	641.	1004.	490.	696.	1031.	998.	96.	4955.
8	790.	1096.	541.	743.	1404.	1054.	90.	5719.
9	615.	1112.	552.	765.	2029.	1119.	160.	6353.
10	653.	1123.	560.	743.	2713.	1206.	108.	7107.
11	737.	1101.	297.	700.	3185.	633.	105.	6757.
12	769.	1189.	326.	691.	3523.	683.	101.	7282.
13	796.	1230.	312.	648.	3640.	744.	118.	7488.
14	879.	1296.	362.	605.	3741.	700.	110.	7694.
15	899.	1373.	362.	562.	3858.	744.	118.	7916.
16	933.	1437.	365.	571.	3851.	700.	110.	7956.
17	975.	1449.	366.	562.	3858.	779.	118.	8107.
18	962.	1536.	350.	571.	3851.	735.	110.	8114.
19	948.	1560.	357.	562.	3838.	786.	122.	8173.
20	929.	1583.	341.	571.	3830.	785.	114.	8153.

CUMULATIVE BCF RESERVES ADDED

YR	NGP - WILLIS.	ROCKY MTN.	OTHER WESTERN	S.W. APPR.	OTHER S.W.	EASTERN	MID CONT.	TOTAL U.S.
1	25.	202.	152.	54.	174.	140.	20.	768.
2	105.	571.	351.	127.	363.	394.	54.	1963.
3	255.	1130.	526.	228.	642.	770.	105.	3656.
4	479.	1905.	754.	452.	1016.	1353.	156.	6113.
5	843.	2764.	1069.	840.	1388.	2091.	227.	9222.
6	1377.	3669.	1464.	1417.	2014.	2973.	302.	13216.
7	2018.	4673.	1954.	2113.	3045.	3971.	398.	18171.
8	2808.	5771.	2494.	2856.	4448.	5025.	488.	23890.
9	3423.	6883.	3046.	3621.	6478.	6144.	648.	30243.
10	4076.	8006.	3606.	4364.	9191.	7350.	756.	37349.
11	4813.	9108.	3903.	5063.	12376.	7983.	861.	44107.
12	5582.	10297.	4229.	5754.	15899.	8666.	962.	51389.
13	6378.	11527.	4541.	6403.	19539.	9410.	1079.	58877.
14	7257.	12823.	4903.	7008.	23280.	10111.	1189.	66571.
15	8156.	14196.	5266.	7570.	27138.	10855.	1307.	74487.
16	9089.	15633.	5620.	8140.	30989.	11555.	1416.	82443.
17	10064.	17082.	5986.	8703.	34848.	12334.	1534.	90550.
18	11026.	18618.	6336.	9273.	38698.	13069.	1644.	98664.
19	11974.	20179.	6693.	9835.	42536.	13854.	1766.	106838.
20	12903.	21761.	7035.	10406.	46366.	14659.	1880.	114990.

TABLE E-14 (Continued)

Well Drilling Committment Scenario Summary
(Half-Standard Scenario)

NO. WELLS ANNUALLY COMMITTED FOR DRILLING

YR	NGP - WILLIS.	ROCKY MTN.	OTHER WESTERN	S.W. APPR.	OTHER S.W.	EASTERN	MID CONT.	TOTAL U.S.
1	21.	106.	175.	43.	104.	169.	36.	654.
2	70.	186.	214.	40.	107.	310.	58.	985.
3	158.	281.	202.	63.	135.	453.	85.	1377.
4	216.	386.	252.	84.	224.	712.	85.	1959.
5	338.	424.	333.	174.	228.	881.	121.	2499.
6	489.	443.	407.	227.	359.	1025.	121.	3071.
7	594.	487.	467.	318.	589.	1133.	158.	3746.
8	716.	542.	524.	323.	789.	1173.	146.	4213.
9	423.	557.	535.	298.	1047.	1256.	213.	4328.
10	456.	556.	540.	323.	1307.	1314.	147.	4642.
11	523.	557.	253.	284.	1426.	493.	91.	3627.
12	554.	582.	269.	301.	1551.	525.	88.	3870.
13	573.	618.	254.	262.	1571.	568.	100.	3946.
14	639.	652.	283.	263.	1579.	537.	94.	4047.
15	671.	708.	285.	224.	1599.	568.	100.	4153.
16	694.	750.	291.	248.	1593.	537.	94.	4207.
17	724.	759.	286.	224.	1599.	583.	100.	4275.
18	722.	811.	285.	248.	1593.	552.	94.	4305.
19	709.	828.	277.	224.	1574.	589.	104.	4305.
20	694.	839.	276.	248.	1568.	596.	98.	4319.

CUMULATIVE WELLS COMMITTED FOR DRILLING

YR	NGP - WILLIS.	ROCKY MTN.	OTHER WESTERN	S.W. APPR.	OTHER S.W.	EASTERN	MID CONT.	TOTAL U.S.
1	21.	106.	175.	43.	104.	169.	36.	654.
2	91.	292.	389.	83.	211.	479.	94.	1639.
3	249.	573.	591.	146.	346.	932.	179.	3016.
4	465.	959.	843.	230.	570.	1644.	264.	4975.
5	803.	1383.	1176.	404.	798.	2525.	385.	7474.
6	1292.	1826.	1583.	631.	1157.	3550.	506.	10545.
7	1886.	2313.	2050.	949.	1746.	4683.	664.	14291.
8	2602.	2855.	2574.	1272.	2535.	5856.	810.	18504.
9	3025.	3412.	3109.	1570.	3582.	7111.	1023.	22832.
10	3481.	3967.	3649.	1893.	4889.	8425.	1170.	27474.
11	4004.	4524.	3902.	2177.	6315.	8918.	1261.	31101.
12	4558.	5106.	4171.	2478.	7866.	9443.	1349.	34971.
13	5131.	5724.	4425.	2740.	9437.	10011.	1449.	38917.
14	5770.	6376.	4708.	3003.	11016.	10548.	1543.	42964.
15	6441.	7084.	4991.	3227.	12615.	11116.	1643.	47117.
16	7135.	7834.	5282.	3475.	14208.	11653.	1737.	51324.
17	7859.	8593.	5568.	3699.	15807.	12236.	1837.	55599.
18	8581.	9404.	5853.	3947.	17400.	12788.	1931.	59904.
19	9290.	10232.	6130.	4171.	18974.	13377.	2035.	64209.
20	9984.	11071.	6406.	4419.	20542.	13973.	2133.	68528.

TABLE E-14 (Continued)
Producing Rate Per Committed Well Scenario Summary
(Half-Standard Scenario)

ANNUAL BCF GAS PRODUCTION PER COMMITTED WELL

YR	NGP - WILLIS.	ROCKY MTN.	OTHER WESTERN	S.W. APPR.	OTHER S.W.	EASTERN	MID CONT.	TOTAL U.S.
1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	0.001	0.027	0.013	0.019	0.022	0.003	0.004	0.012
5	0.004	0.083	0.040	0.025	0.055	0.012	0.009	0.031
6	0.009	0.171	0.068	0.036	0.072	0.026	0.018	0.056
7	0.018	0.266	0.091	0.059	0.071	0.045	0.023	0.079
8	0.030	0.351	0.113	0.114	0.075	0.071	0.045	0.108
9	0.088	0.451	0.152	0.224	0.082	0.100	0.045	0.152
10	0.132	0.566	0.203	0.312	0.099	0.134	0.088	0.195
11	0.172	0.674	0.564	0.485	0.137	0.466	0.184	0.327
12	0.224	0.751	0.658	0.586	0.195	0.540	0.242	0.393
13	0.276	0.802	0.824	0.809	0.287	0.598	0.262	0.479
14	0.294	0.839	0.815	0.939	0.395	0.721	0.332	0.557
15	0.324	0.844	0.847	1.228	0.505	0.733	0.373	0.624
16	0.357	0.861	0.820	1.227	0.625	0.796	0.438	0.689
17	0.387	0.916	0.838	1.452	0.737	0.753	0.464	0.750
18	0.433	0.920	0.857	1.398	0.852	0.822	0.524	0.816
19	0.489	0.966	0.909	1.615	0.971	0.797	0.527	0.886
20	0.550	1.016	0.944	1.530	1.075	0.818	0.585	0.950

CUM. BCF GAS PROD. PER COMMITTED WELL

YR	NGP - WILLIS.	ROCKY MTN.	OTHER WESTERN	S.W. APPR.	OTHER S.W.	EASTERN	MID CONT.	TOTAL U.S.
1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	0.000	0.011	0.004	0.007	0.009	0.001	0.001	0.005
5	0.002	0.033	0.014	0.015	0.022	0.005	0.004	0.014
6	0.005	0.067	0.028	0.022	0.038	0.011	0.007	0.026
7	0.009	0.109	0.042	0.035	0.049	0.019	0.011	0.040
8	0.014	0.154	0.057	0.055	0.057	0.030	0.017	0.055
9	0.025	0.203	0.073	0.087	0.064	0.042	0.023	0.074
10	0.039	0.254	0.092	0.125	0.073	0.057	0.031	0.094
11	0.056	0.305	0.123	0.172	0.088	0.079	0.042	0.121
12	0.077	0.366	0.157	0.223	0.109	0.105	0.055	0.151
13	0.099	0.404	0.196	0.279	0.139	0.133	0.070	0.185
14	0.120	0.449	0.233	0.336	0.175	0.163	0.086	0.220
15	0.142	0.488	0.268	0.398	0.217	0.192	0.103	0.255
16	0.163	0.524	0.298	0.457	0.263	0.220	0.121	0.291
17	0.183	0.559	0.326	0.518	0.311	0.245	0.140	0.326
18	0.204	0.590	0.352	0.573	0.360	0.270	0.159	0.361
19	0.226	0.620	0.377	0.629	0.411	0.294	0.177	0.397
20	0.249	0.650	0.401	0.679	0.462	0.316	0.196	0.431

TABLE E-14 (Continued)

Reserves Per Committed Well Scenario Summary
(Half-Standard Scenario)

ANNUAL BCF RESERVES ADDED PER COMMITTED WELL

YR	NGP - WILLIS.	ROCKY MTN.	OTHER WESTERN	S.W. APPR.	OTHER S.W.	EASTERN	MID CONT.	TOTAL U.S.
1	1.190	1.909	0.869	1.260	1.674	0.830	0.567	1.175
2	1.140	1.983	0.928	1.810	1.761	0.818	0.574	1.213
3	0.949	1.989	0.868	1.616	2.073	0.829	0.600	1.229
4	1.037	2.006	0.905	2.656	1.668	0.819	0.600	1.254
5	1.078	2.028	0.946	2.230	1.630	0.838	0.590	1.244
6	1.091	2.043	0.970	2.545	1.744	0.860	0.622	1.300
7	1.660	2.062	1.046	2.187	1.751	0.881	0.606	1.323
8	1.103	2.025	1.031	2.299	1.779	0.899	0.617	1.357
9	1.454	1.997	1.031	2.568	1.938	0.892	0.751	1.468
10	1.432	2.024	1.038	2.299	2.076	0.918	0.735	1.531
11	1.409	1.977	1.174	2.464	2.233	1.284	1.148	1.863
12	1.388	2.043	1.211	2.296	2.271	1.302	1.150	1.882
13	1.396	1.996	1.229	2.474	2.317	1.310	1.175	1.898
14	1.376	1.988	1.280	2.300	2.369	1.304	1.168	1.901
15	1.389	1.989	1.280	2.510	2.413	1.310	1.175	1.906
16	1.344	1.916	1.219	2.301	2.417	1.304	1.168	1.891
17	1.346	1.910	1.279	2.510	2.413	1.336	1.175	1.896
18	1.333	1.894	1.227	2.301	2.417	1.331	1.168	1.885
19	1.337	1.885	1.290	2.510	2.438	1.354	1.171	1.899
20	1.339	1.887	1.237	2.301	2.443	1.317	1.164	1.888

CUM. RESERVES ADDED PER COMMITTED WELL, (BCF)

YR	NGP - WILLIS.	ROCKY MTN.	OTHER WESTERN	S.W. APPR.	OTHER S.W.	EASTERN	MID CONT.	TOTAL U.S.
1	1.190	1.909	0.869	1.260	1.674	0.830	0.567	1.175
2	1.152	1.956	0.901	1.525	1.718	0.822	0.571	1.198
3	1.023	1.972	0.890	1.564	1.857	0.826	0.585	1.212
4	1.029	1.986	0.894	1.963	1.782	0.823	0.590	1.229
5	1.050	1.999	0.909	2.078	1.739	0.828	0.590	1.234
6	1.065	2.009	0.925	2.246	1.740	0.837	0.598	1.253
7	1.070	2.020	0.953	2.226	1.744	0.848	0.600	1.271
8	1.079	2.021	0.969	2.245	1.755	0.858	0.603	1.291
9	1.132	2.017	0.980	2.306	1.808	0.864	0.634	1.325
10	1.171	2.018	0.988	2.305	1.880	0.872	0.646	1.359
11	1.202	2.013	1.000	2.326	1.960	0.895	0.683	1.418
12	1.225	2.017	1.014	2.322	2.021	0.918	0.713	1.469
13	1.243	2.014	1.026	2.337	2.070	0.940	0.745	1.513
14	1.258	2.011	1.042	2.334	2.113	0.959	0.771	1.549
15	1.266	2.004	1.055	2.346	2.151	0.977	0.795	1.581
16	1.274	1.995	1.064	2.343	2.181	0.992	0.815	1.606
17	1.281	1.988	1.075	2.353	2.205	1.008	0.835	1.629
18	1.285	1.980	1.083	2.349	2.224	1.022	0.851	1.647
19	1.289	1.972	1.092	2.358	2.242	1.036	0.868	1.664
20	1.292	1.966	1.098	2.355	2.257	1.048	0.881	1.678

TABLE E-14 (Continued)
Production Rate vs. Remaining Reserves
(Half-Standard Scenario)

REMAINING BCF RESERVES = CUM. RES - CUM. PROD

YR	NGP - WILLISTON	ROCKY MOUNTAINS	OTHER WESTERN	SOUTHWEST APPRAISED	OTHER SOUTHWEST	EASTERN	MID CONTINENT	TOTAL U.S.
1	25.000	202.400	152.000	54.200	174.100	140.300	20.400	768.399
2	104.800	571.200	350.600	126.600	362.500	393.900	53.700	1963.299
3	254.800	1130.000	525.900	228.400	642.400	769.600	104.700	3655.798
4	478.472	1893.959	750.726	449.912	1010.984	1350.610	155.340	6089.996
5	841.676	2718.459	1052.413	833.713	1370.079	2078.175	225.612	9120.121
6	1370.669	3547.757	1419.798	1403.224	1970.185	2932.618	298.677	12942.922
7	2061.515	4422.277	1867.128	2079.817	2959.634	3879.583	390.671	17600.621
8	2770.388	5329.742	2348.510	2785.539	4304.391	4850.234	474.158	22862.961
9	3348.037	6190.937	2818.817	3484.038	6248.187	5843.480	624.437	28557.934
10	3941.053	7000.078	3269.375	4126.113	8831.809	6873.480	719.530	34761.437
11	4588.125	7725.723	3723.680	4688.152	11821.473	7276.816	807.277	40331.262
12	5233.062	8477.672	3572.328	5202.941	15041.559	7676.781	887.165	46091.551
13	5871.359	9211.980	3675.350	5639.223	18231.164	8081.551	978.447	51689.102
14	6562.180	9961.320	3807.006	5997.359	21348.340	8394.676	1057.013	57127.898
15	7243.625	10736.387	3929.568	6284.555	24399.625	8722.715	1137.251	62453.680
16	7928.064	11527.531	4045.731	6550.855	27254.633	8995.906	1205.867	67509.062
17	8623.355	12281.734	4171.656	6787.883	29934.316	9335.543	1276.925	72411.312
18	9272.727	13071.961	4277.324	7011.793	32426.992	9616.727	1337.439	77014.812
19	9873.898	13832.887	4382.816	7212.293	34736.488	9932.887	1404.408	81375.500
20	10421.246	14563.480	4463.656	7403.477	36881.238	10230.055	1461.142	85424.062

PERCENT BCF ANNUAL PROD / BCF REMAIN RES

YR	NGP - WILLIS.	ROCKY MTN.	OTHER WESTERN	S.W. APPR.	OTHER S.W.	EASTERN	MID CONT.	TOTAL U.S.
1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	0.048	0.557	0.436	0.353	0.496	0.162	0.232	0.381
5	0.154	1.302	1.275	0.516	0.913	0.507	0.500	0.862
6	0.314	2.131	1.938	0.584	1.314	0.926	0.749	1.320
7	0.527	2.928	2.264	0.909	1.411	1.315	0.948	1.691
8	0.766	3.566	2.517	1.327	1.367	1.727	1.395	1.997
9	1.116	4.058	2.891	1.917	1.368	2.154	1.541	2.303
10	1.525	4.485	3.360	2.439	1.469	2.561	1.808	2.599
11	1.960	4.862	4.165	2.938	1.650	3.155	2.075	2.944
12	2.367	5.159	4.956	3.389	2.014	3.692	2.402	3.303
13	2.690	5.382	5.691	3.758	2.470	4.200	2.680	3.658
14	2.868	5.490	6.058	4.116	2.924	4.613	2.955	3.948
15	3.001	5.565	6.101	4.376	3.308	4.771	3.276	4.147
16	3.127	5.601	5.898	4.645	3.653	4.749	3.415	4.297
17	3.248	5.660	5.748	4.790	3.938	4.702	3.637	4.425
18	3.375	5.707	5.708	4.944	4.188	4.717	3.685	4.559
19	3.515	5.780	5.745	5.015	4.400	4.726	3.904	4.685
20	3.663	5.852	5.837	5.125	4.570	4.766	3.926	4.804

TABLE E-14 (Continued)
Investment Committment Scenario Summary
(Half-Standard Scenario)

MM-DOLLARS INVESTMENT COMMITTED ANNUALLY

YR	NGP - WILLIS.	ROCKY MTN.	OTHER WESTERN	S.W. APPR.	OTHER S.W.	EASTERN	MID CONT.	TOTAL U.S.
1	7.	109.	102.	32.	88.	93.	14.	445.
2	22.	188.	138.	37.	88.	173.	22.	667.
3	48.	285.	117.	52.	141.	250.	29.	920.
4	71.	384.	163.	108.	192.	376.	29.	1324.
5	123.	434.	200.	186.	188.	468.	43.	1643.
6	185.	481.	269.	268.	314.	579.	39.	2135.
7	232.	589.	333.	322.	513.	640.	53.	2681.
8	289.	695.	384.	350.	687.	677.	47.	3129.
9	226.	754.	393.	352.	946.	722.	88.	3481.
10	242.	784.	391.	350.	1220.	769.	58.	3814.
11	275.	808.	245.	329.	1410.	350.	54.	3470.
12	288.	849.	269.	328.	1570.	358.	51.	3712.
13	297.	894.	253.	306.	1629.	399.	58.	3835.
14	328.	949.	290.	290.	1681.	364.	54.	3955.
15	340.	1022.	290.	268.	1740.	399.	58.	4115.
16	352.	1062.	286.	275.	1736.	364.	54.	4129.
17	369.	1070.	295.	268.	1740.	414.	58.	4213.
18	366.	1134.	281.	275.	1736.	379.	54.	4225.
19	360.	1166.	284.	268.	1726.	417.	59.	4279.
20	352.	1188.	270.	275.	1722.	410.	55.	4272.

CUM. MM-DOLLARS INVESTMENT COMMITTED

YR	NGP - WILLIS.	ROCKY MTN.	OTHER WESTERN	S.W. APPR.	OTHER S.W.	EASTERN	MID CONT.	TOTAL U.S.
1	7.	109.	102.	32.	88.	93.	14.	445.
2	29.	298.	239.	69.	176.	266.	36.	1112.
3	76.	580.	356.	120.	317.	517.	65.	2032.
4	148.	965.	519.	228.	509.	893.	94.	3356.
5	271.	1399.	719.	415.	697.	1361.	137.	4999.
6	456.	1880.	988.	683.	1011.	1940.	176.	7134.
7	688.	2468.	1321.	1004.	1525.	2580.	229.	9815.
8	976.	3163.	1705.	1355.	2211.	3257.	276.	12943.
9	1202.	3917.	2097.	1707.	3157.	3979.	365.	16424.
10	1445.	4701.	2488.	2057.	4377.	4748.	423.	20238.
11	1720.	5509.	2733.	2386.	5787.	5098.	476.	23708.
12	2007.	6358.	3001.	2713.	7357.	5457.	527.	27421.
13	2304.	7252.	3254.	3019.	8986.	5856.	585.	31256.
14	2632.	8201.	3543.	3309.	10667.	6220.	639.	35211.
15	2972.	9222.	3833.	3578.	12406.	6619.	696.	39326.
16	3323.	10284.	4119.	3853.	14142.	6983.	750.	43454.
17	3692.	11354.	4414.	4121.	15882.	7397.	807.	47667.
18	4057.	12488.	4696.	4396.	17617.	7776.	861.	51892.
19	4417.	13654.	4980.	4664.	19343.	8193.	920.	56171.
20	4769.	14842.	5250.	4939.	21065.	8603.	975.	60443.

TABLE E-14 (Continued)

Cash Flow Scenario Summary
(Half-Standard Scenario)

ANNUAL CASH FLOW MM-DOLLARS

YR	NGP - WILLISTON	ROCKY MOUNTAINS	OTHER WESTERN	SOUTHWEST APPRAISED	OTHER SOUTHWEST	EASTERN	MID CONTINENT	TOTAL U.S.
1	-0.134	-0.309	-0.297	-0.157	-0.698	-0.466	-0.051	-2.112
2	-1.106	-4.745	-4.169	-1.102	-3.436	-4.070	-0.558	-19.186
3	-3.652	-23.156	-12.262	-6.165	-17.946	-13.432	-1.427	-78.040
4	-7.071	-20.079	-13.651	-9.517	-22.358	-19.996	-3.850	-95.923
5	-11.186	-5.511	-14.754	-10.139	-25.164	-37.883	-5.271	-109.907
6	-16.829	49.167	2.821	-21.787	-9.042	-37.195	-5.581	-38.446
7	-23.686	130.208	21.601	-18.389	12.014	-27.576	-6.204	87.967
8	-22.303	228.073	38.592	-8.321	24.180	-3.578	-5.028	251.615
9	-12.654	332.960	63.014	39.401	38.602	38.301	0.264	499.886
10	11.132	443.028	102.538	91.742	70.038	98.440	2.099	819.017
11	50.384	549.637	154.416	156.308	109.800	183.584	7.485	1211.613
12	90.924	657.155	222.413	237.873	221.097	283.614	12.543	1725.619
13	155.727	772.955	296.154	310.906	417.006	403.765	19.927	2376.439
14	216.219	868.635	350.079	390.045	698.203	499.815	32.441	3055.438
15	265.708	964.392	396.248	449.596	1021.750	636.856	45.125	3779.675
16	314.420	1053.975	400.640	521.059	1376.695	688.229	54.058	4409.070
17	370.194	1144.796	404.553	568.425	1725.606	724.042	63.959	5001.570
18	423.771	1236.574	407.665	622.855	2089.213	756.055	69.543	5605.668
19	480.916	1335.387	419.792	655.694	2441.504	786.532	80.467	6200.285
20	543.463	1430.132	433.739	700.385	2772.986	824.718	85.588	6791.004

CUMULATIVE MM-DOLLARS CASH FLOW

YR	NGP - WILLISTON	ROCKY MOUNTAINS	OTHER WESTERN	SOUTHWEST APPRAISED	OTHER SOUTHWEST	EASTERN	MID CONTINENT	TOTAL U.S.
1	-0.134	-0.309	-0.297	-0.157	-0.698	-0.466	-0.051	-2.112
2	-1.240	-5.054	-4.466	-1.260	-4.134	-4.536	-0.608	-21.298
3	-4.892	-28.210	-16.728	-7.425	-22.080	-17.967	-2.035	-99.337
4	-11.962	-48.289	-29.779	-16.942	-44.438	-37.963	-5.885	-195.260
5	-23.148	-53.800	-44.533	-27.081	-69.603	-75.846	-11.156	-305.167
6	-39.977	-4.633	-41.713	-48.868	-78.644	-113.041	-16.737	-343.613
7	-63.663	125.574	-20.111	-67.257	-66.630	-140.617	-22.941	-255.646
8	-85.965	353.647	18.481	-75.578	-42.450	-144.195	-27.970	-4.031
9	-98.619	686.607	81.494	-36.177	-3.848	-105.895	-27.705	495.855
10	-87.487	1129.635	184.032	55.565	66.190	-7.455	-25.606	1314.873
11	-37.103	1679.273	338.447	211.873	175.990	176.130	-18.121	2526.486
12	53.821	2336.427	560.861	449.746	397.087	459.743	-5.578	4252.102
13	209.548	3109.382	857.015	760.652	814.093	863.508	14.349	6628.539
14	425.767	3978.018	1207.094	1150.698	1512.296	1363.323	46.790	9683.977
15	691.475	4942.406	1603.342	1600.293	2534.046	2000.179	91.915	13463.648
16	1005.895	5996.379	2003.981	2121.352	3910.741	2688.409	145.973	17872.719
17	1376.089	7141.172	2408.534	2689.777	5636.344	3412.451	209.932	22874.289
18	1799.860	8377.746	2816.199	3312.632	7725.555	4168.504	279.475	28479.957
19	2280.775	9713.133	3235.990	3968.326	10167.059	4965.035	359.942	34680.242
20	2824.238	11143.262	3669.729	4668.711	12940.043	5779.750	445.530	41471.246

TABLE E-14 (Continued)

Investment Per Committed Wells Scenario Summary
(Half-Standard Scenario)

ANNUAL MM-DOLLARS PER WELL (COMMITTED)

YR	NGP - WILLIS.	ROCKY MTN.	OTHER WESTERN	S.W. APPR.	OTHER S.W.	EASTERN	MID CONT.	TOTAL U.S.
1	0.319	1.031	0.581	0.744	0.848	0.561	0.383	0.680
2	0.313	1.013	0.643	0.915	0.821	0.558	0.378	0.677
3	0.303	1.006	0.581	0.819	1.041	0.553	0.345	0.668
4	0.329	0.995	0.646	1.285	0.859	0.528	0.345	0.676
5	0.365	1.024	0.601	1.071	0.825	0.531	0.356	0.657
6	0.378	1.086	0.660	1.181	0.875	0.565	0.321	0.695
7	0.391	1.208	0.713	1.012	0.871	0.565	0.333	0.716
8	0.403	1.282	0.732	1.085	0.870	0.577	0.325	0.743
9	0.534	1.354	0.734	1.182	0.903	0.575	0.415	0.804
10	0.532	1.412	0.724	1.085	0.933	0.585	0.397	0.822
11	0.526	1.451	0.966	1.157	0.989	0.711	0.588	0.957
12	0.519	1.459	0.999	1.089	1.012	0.683	0.580	0.959
13	0.518	1.447	0.994	1.168	1.037	0.702	0.575	0.972
14	0.513	1.456	1.023	1.103	1.064	0.678	0.571	0.977
15	0.506	1.443	1.023	1.198	1.088	0.702	0.575	0.991
16	0.506	1.416	0.984	1.109	1.090	0.678	0.571	0.981
17	0.509	1.409	1.032	1.198	1.088	0.710	0.575	0.985
18	0.506	1.399	0.987	1.109	1.090	0.687	0.571	0.981
19	0.507	1.408	1.026	1.198	1.096	0.707	0.565	0.994
20	0.508	1.415	0.979	1.109	1.098	0.688	0.561	0.989

CUM. MM-DOLLARS PER WELL (COMMITTED)

YR	NGP - WILLIS.	ROCKY MTN.	OTHER WESTERN	S.W. APPR.	OTHER S.W.	EASTERN	MID CONT.	TOTAL U.S.
1	0.319	1.031	0.581	0.744	0.848	0.561	0.383	0.680
2	0.314	1.020	0.615	0.827	0.834	0.556	0.380	0.678
3	0.307	1.013	0.603	0.823	0.915	0.554	0.363	0.674
4	0.317	1.006	0.610	0.992	0.893	0.543	0.357	0.674
5	0.337	1.011	0.612	1.026	0.873	0.539	0.357	0.669
6	0.353	1.030	0.624	1.082	0.874	0.547	0.348	0.676
7	0.365	1.067	0.644	1.058	0.873	0.551	0.345	0.687
8	0.375	1.108	0.662	1.065	0.872	0.556	0.341	0.699
9	0.397	1.148	0.675	1.087	0.881	0.560	0.356	0.719
10	0.415	1.185	0.682	1.087	0.895	0.564	0.361	0.737
11	0.429	1.218	0.700	1.096	0.916	0.572	0.378	0.762
12	0.440	1.245	0.720	1.095	0.935	0.578	0.391	0.784
13	0.449	1.267	0.735	1.102	0.952	0.585	0.404	0.803
14	0.456	1.286	0.753	1.102	0.968	0.590	0.414	0.820
15	0.461	1.302	0.768	1.109	0.983	0.595	0.424	0.835
16	0.466	1.313	0.780	1.109	0.995	0.599	0.432	0.847
17	0.470	1.321	0.793	1.114	1.005	0.605	0.439	0.857
18	0.473	1.328	0.802	1.114	1.012	0.608	0.446	0.866
19	0.475	1.334	0.812	1.118	1.019	0.612	0.452	0.875
20	0.478	1.341	0.820	1.118	1.025	0.616	0.457	0.882

TABLE E-14 (Continued)
Investment/Reserves Ratio Scenario Summary
(Half-Standard Scenario)

ANNUAL MM-DOLLARS COMMITTED PER BCF RESERVES

YR	NGP - WILLIS.	ROCKY MTN.	OTHER WESTERN	S.W. APPR.	OTHER S.W.	EASTERN	MID CONT.	TOTAL U.S.
1	0.268	0.540	0.668	0.590	0.507	0.664	0.676	0.579
2	0.274	0.511	0.692	0.506	0.466	0.683	0.658	0.558
3	0.319	0.506	0.669	0.507	0.502	0.666	0.575	0.543
4	0.318	0.496	0.714	0.484	0.515	0.645	0.575	0.539
5	0.338	0.505	0.635	0.480	0.506	0.634	0.604	0.529
6	0.340	0.532	0.680	0.464	0.502	0.657	0.517	0.535
7	0.362	0.586	0.680	0.463	0.498	0.641	0.550	0.541
8	0.365	0.633	0.710	0.472	0.489	0.642	0.526	0.547
9	0.367	0.678	0.711	0.460	0.466	0.645	0.552	0.548
10	0.371	0.698	0.698	0.472	0.450	0.638	0.539	0.537
11	0.373	0.734	0.824	0.469	0.443	0.564	0.512	0.514
12	0.374	0.714	0.825	0.474	0.446	0.524	0.504	0.510
13	0.373	0.727	0.809	0.472	0.448	0.536	0.489	0.512
14	0.373	0.732	0.799	0.480	0.449	0.520	0.489	0.514
15	0.378	0.744	0.799	0.477	0.451	0.536	0.489	0.520
16	0.377	0.739	0.807	0.482	0.451	0.520	0.489	0.519
17	0.378	0.738	0.807	0.477	0.451	0.532	0.489	0.520
18	0.380	0.738	0.804	0.482	0.451	0.516	0.489	0.521
19	0.379	0.747	0.796	0.477	0.450	0.530	0.483	0.524
20	0.379	0.750	0.792	0.482	0.450	0.522	0.482	0.524

CUM. MM-DOLLARS COMMITTED PER BCF RESERVES

YR	NGP - WILLIS.	ROCKY MTN.	OTHER WESTERN	S.W. APPR.	OTHER S.W.	EASTERN	MID CONT.	TOTAL U.S.
1	0.268	0.540	0.668	0.590	0.507	0.664	0.676	0.579
2	0.273	0.521	0.682	0.542	0.486	0.676	0.665	0.566
3	0.300	0.514	0.678	0.526	0.493	0.671	0.621	0.556
4	0.306	0.506	0.689	0.505	0.501	0.660	0.606	0.549
5	0.321	0.506	0.673	0.494	0.502	0.651	0.605	0.542
6	0.331	0.512	0.675	0.482	0.502	0.653	0.583	0.540
7	0.341	0.528	0.676	0.475	0.501	0.650	0.575	0.540
8	0.348	0.548	0.683	0.474	0.497	0.648	0.566	0.542
9	0.351	0.569	0.688	0.471	0.487	0.648	0.563	0.543
10	0.354	0.587	0.690	0.471	0.476	0.646	0.559	0.542
11	0.357	0.605	0.700	0.471	0.468	0.639	0.554	0.538
12	0.360	0.617	0.710	0.472	0.463	0.630	0.548	0.534
13	0.361	0.629	0.717	0.472	0.460	0.622	0.542	0.531
14	0.363	0.640	0.723	0.472	0.458	0.615	0.537	0.529
15	0.364	0.650	0.728	0.473	0.457	0.610	0.533	0.528
16	0.366	0.658	0.733	0.473	0.456	0.604	0.529	0.527
17	0.367	0.665	0.737	0.474	0.456	0.600	0.526	0.526
18	0.368	0.671	0.741	0.474	0.455	0.595	0.524	0.526
19	0.369	0.677	0.744	0.474	0.455	0.591	0.521	0.526
20	0.370	0.682	0.746	0.475	0.454	0.588	0.519	0.526

TABLE E-15

Producing Rate Scenario Summary
(Twice-Standard Scenario)

ANNUAL BCF GAS PRODUCTION

YR	NGP - WILLISTON	ROCKY MOUNTAINS	OTHER WESTERN	SOUTHWEST APPRAISED	OTHER SOUTHWEST	EASTERN	MID CONTINENT	TOTAL U.S.
1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	0.678	104.903	7.629	2.306	10.587	4.985	0.360	131.450
5	3.234	135.477	27.957	7.597	25.115	22.065	1.541	222.985
6	10.444	221.621	57.880	15.577	50.921	54.725	3.873	415.047
7	24.090	320.563	85.237	40.535	82.640	103.831	8.054	664.949
8	46.908	445.341	120.921	74.835	119.711	187.026	13.170	1007.912
9	84.358	694.674	180.904	134.591	174.019	309.674	19.674	1508.093
10	153.875	800.565	266.858	200.966	257.015	507.659	26.858	2213.796
11	276.100	1044.698	370.700	275.904	385.937	824.305	34.165	3211.810
12	461.709	1351.892	482.680	350.567	601.289	1205.482	42.786	4496.402
13	701.335	1692.391	587.104	425.806	897.273	1507.865	52.120	5863.887
14	969.431	2065.039	679.634	490.987	1246.875	1793.499	60.585	7306.043
15	1256.038	2438.862	764.329	552.149	1609.781	2066.716	71.325	8749.191
16	1551.091	2806.115	845.624	606.515	1989.677	2325.769	81.340	10206.113
17	1848.448	3159.061	932.518	653.142	2357.224	2611.901	89.326	11651.609
18	2141.612	3486.277	1021.138	691.946	2717.799	2905.554	97.779	13062.094
19	2422.492	3765.011	1106.634	726.172	3055.674	3194.527	106.135	14375.633
20	2681.167	4001.389	1184.062	757.291	3372.632	3471.322	114.131	15582.582

CUMULATIVE BCF GAS PRODUCTION

YR	NGP - WILLISTON	ROCKY MOUNTAINS	OTHER WESTERN	SOUTHWEST APPRAISED	OTHER SOUTHWEST	EASTERN	MID CONTINENT	TOTAL U.S.
1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	0.678	104.903	7.629	2.306	10.587	4.985	0.360	131.450
5	3.912	240.380	35.586	9.903	35.701	27.050	1.901	354.435
6	14.356	462.007	93.467	25.480	86.623	81.775	5.774	769.482
7	38.447	782.570	178.704	66.015	169.263	185.607	13.828	1434.431
8	85.355	1227.911	299.625	140.850	288.973	372.633	26.997	2442.343
9	169.713	1632.585	480.529	275.441	462.992	682.306	46.871	3950.436
10	323.588	2433.150	747.387	476.407	720.008	1189.965	73.729	6164.230
11	599.689	3077.848	1118.087	752.311	1105.945	2014.270	107.895	9376.039
12	1061.398	4429.736	1600.767	1102.878	1707.233	3219.752	150.680	13872.441
13	1762.733	6122.129	2187.871	1528.684	2604.507	4727.613	202.801	19736.328
14	2732.164	8787.164	2867.505	2019.671	3851.382	6521.109	263.386	27042.371
15	3988.202	11226.023	3631.833	2571.819	5461.160	8577.824	334.711	35791.562
16	5539.289	14032.137	4477.453	3178.335	7450.836	10903.590	416.051	45997.676
17	7387.734	17191.195	5409.969	3831.476	9808.059	13515.488	505.377	57649.285
18	9529.344	20677.469	6431.105	4523.422	12525.855	16421.039	603.156	70711.375
19	11951.832	24442.477	7536.738	5249.594	15581.527	19615.562	709.291	85087.000
20	14632.996	28443.863	8721.398	6006.883	18954.156	23086.883	823.422	100669.562

TABLE E-15 (Continued)

Reserve Scenario Summary
(Twice-Standard Scenario)

BCF RESERVES ADDED ANNUALLY

YR	NGP - WILLIS.	ROCKY MTN.	OTHER WESTERN	S.W. APPR.	OTHER S.W.	EASTERN	MID CONT.	TOTAL U.S.
1	77.	1264.	354.	89.	363.	312.	31.	2489.
2	167.	765.	365.	150.	363.	480.	60.	2350.
3	326.	1129.	374.	200.	564.	735.	105.	3433.
4	502.	1525.	404.	525.	693.	1311.	132.	5092.
5	761.	1822.	718.	741.	783.	2126.	140.	7091.
6	1430.	2348.	1079.	1138.	1295.	2829.	158.	10277.
7	2909.	3134.	1340.	1404.	1926.	8725.	171.	19610.
8	4230.	3898.	1581.	1456.	2838.	4439.	175.	18618.
9	4811.	4681.	1717.	1542.	4068.	5168.	266.	22452.
10	5685.	5540.	1747.	1477.	5435.	6350.	250.	26483.
11	6167.	6250.	1774.	1391.	6405.	5928.	183.	28098.
12	6570.	6702.	1979.	1391.	7054.	6483.	214.	30393.
13	6858.	7151.	2066.	1305.	7272.	6943.	223.	31816.
14	7025.	6996.	2098.	1219.	7491.	7099.	227.	32154.
15	6998.	6913.	2136.	1133.	7709.	7444.	227.	32560.
16	6738.	6573.	2136.	1133.	7709.	7482.	227.	31998.
17	6348.	6448.	2136.	1133.	7709.	7591.	227.	31592.
18	5894.	6174.	2136.	1133.	7709.	7898.	227.	31171.
19	5483.	5831.	2136.	1133.	7709.	7898.	232.	30421.
20	4930.	5563.	2136.	1133.	7172.	7898.	183.	29015.

CUMULATIVE BCF RESERVES ADDED

YR	NGP - WILLIS.	ROCKY MTN.	OTHER WESTERN	S.W. APPR.	OTHER S.W.	EASTERN	MID CONT.	TOTAL U.S.
1	77.	1264.	354.	89.	363.	312.	31.	2489.
2	243.	2029.	719.	239.	725.	792.	91.	4838.
3	569.	3158.	1093.	439.	1289.	1527.	196.	8271.
4	1071.	4683.	1497.	965.	1982.	2839.	328.	13363.
5	1832.	6505.	2215.	1705.	2765.	4965.	468.	20454.
6	3261.	8853.	3294.	2843.	4060.	7794.	625.	30731.
7	6170.	11987.	4634.	4247.	5986.	16519.	796.	50341.
8	10400.	15886.	6216.	5704.	8824.	20959.	972.	68959.
9	15216.	20767.	7932.	7246.	12892.	26126.	1238.	91411.
10	20896.	26307.	9679.	8723.	18326.	32477.	1487.	117894.
11	27063.	32557.	11453.	10114.	24731.	38404.	1670.	145993.
12	33633.	39259.	13432.	11505.	31785.	44887.	1885.	176385.
13	40491.	46409.	15498.	12810.	39057.	51830.	2107.	208202.
14	47515.	53405.	17596.	14028.	46548.	58929.	2335.	240355.
15	54514.	60318.	19732.	15161.	54257.	66372.	2562.	272916.
16	61251.	66891.	21868.	16294.	61966.	73855.	2789.	304914.
17	67599.	73339.	24004.	17427.	69675.	81446.	3016.	336505.
18	73493.	79512.	26140.	18560.	77384.	89344.	3243.	367676.
19	78976.	85343.	28277.	19692.	85093.	97242.	3475.	398097.
20	83905.	90906.	30413.	20825.	92265.	105140.	3658.	427112.

TABLE E-15 (Continued)
Well Drilling Committment Scenario Summary
(Twice-Standard Scenario)

NO. WELLS ANNUALLY COMMITTED FOR DRILLING

YR	NGP - WILLIS.	ROCKY MTN.	OTHER WESTERN	S.W. APPR.	OTHER S.W.	EASTERN	MID CONT.	TOTAL U.S.
1	67.	360.	401.	72.	213.	391.	55.	1559.
2	154.	390.	411.	94.	213.	583.	102.	1947.
3	298.	604.	418.	111.	300.	881.	181.	2793.
4	495.	788.	455.	228.	379.	1565.	229.	4139.
5	715.	912.	700.	315.	419.	2278.	238.	5577.
6	1326.	1200.	1038.	452.	776.	2925.	258.	7975.
7	2450.	1659.	1216.	650.	1148.	9533.	281.	16937.
8	3424.	2138.	1421.	601.	1606.	4272.	285.	13747.
9	3749.	2763.	1557.	638.	2096.	4875.	372.	16050.
10	4381.	3207.	1592.	626.	2621.	5795.	318.	18540.
11	4787.	3675.	1453.	589.	2894.	4676.	160.	18234.
12	5125.	3987.	1568.	589.	3109.	5057.	188.	19623.
13	5395.	4383.	1657.	551.	3137.	5366.	194.	20683.
14	5565.	4335.	1676.	514.	3165.	5509.	197.	20961.
15	5545.	4369.	1720.	476.	3194.	5740.	197.	21241.
16	5321.	4192.	1720.	476.	3194.	5786.	197.	20885.
17	4994.	4149.	1720.	476.	3194.	5909.	197.	20639.
18	4666.	4006.	1720.	476.	3194.	6088.	197.	20347.
19	4291.	3795.	1720.	476.	3194.	6088.	200.	19764.
20	3836.	3653.	1720.	476.	2696.	6088.	157.	18626.

CUMULATIVE WELLS COMMITTED FOR DRILLING

YR	NGP - WILLIS.	ROCKY MTN.	OTHER WESTERN	S.W. APPR.	OTHER S.W.	EASTERN	MID CONT.	TOTAL U.S.
1	67.	360.	401.	72.	213.	391.	55.	1559.
2	221.	750.	812.	166.	426.	974.	157.	3506.
3	519.	1354.	1230.	277.	726.	1855.	338.	6299.
4	1014.	2142.	1685.	505.	1105.	3420.	567.	10438.
5	1729.	3054.	2385.	820.	1524.	5698.	805.	16015.
6	3055.	4254.	3423.	1272.	2300.	8623.	1063.	23990.
7	5505.	5913.	4639.	1922.	3448.	18156.	1344.	40927.
8	8929.	8051.	6060.	2523.	5054.	22428.	1629.	54674.
9	12678.	10814.	7617.	3161.	7150.	27303.	2001.	70724.
10	17059.	14021.	9209.	3787.	9771.	33098.	2319.	89264.
11	21846.	17696.	10662.	4376.	12665.	37774.	2479.	107498.
12	26971.	21683.	12230.	4965.	15774.	42831.	2667.	127121.
13	32366.	26066.	13887.	5516.	18911.	48197.	2861.	147804.
14	37931.	30401.	15563.	6030.	22076.	53706.	3058.	168765.
15	43476.	34770.	17283.	6506.	25270.	59446.	3255.	190006.
16	48797.	38962.	19003.	6982.	28464.	65231.	3452.	210891.
17	53791.	43111.	20723.	7458.	31658.	71140.	3649.	231530.
18	58457.	47117.	22443.	7934.	34852.	77228.	3846.	251877.
19	62748.	50912.	24163.	8410.	38046.	83316.	4046.	271641.
20	66584.	54565.	25883.	8886.	40742.	89404.	4203.	290267.

TABLE E-15 (Continued)
Producing Rate Per Committed Well Scenario Summary
(Twice-Standard Scenario)

ANNUAL BCF GAS PRODUCTION PER COMMITTED WELL

YR	NGP - WILLIS.	ROCKY MTN.	OTHER WESTERN	S.W. APPR.	OTHER S.W.	EASTERN	MID CONT.	TOTAL U.S.
1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	0.001	0.133	0.017	0.010	0.028	0.003	0.002	0.032
5	0.005	0.149	0.040	0.024	0.060	0.010	0.006	0.040
6	0.008	0.185	0.056	0.034	0.066	0.019	0.015	0.052
7	0.010	0.193	0.070	0.062	0.072	0.011	0.029	0.039
8	0.014	0.208	0.085	0.125	0.075	0.044	0.046	0.073
9	0.025	0.219	0.116	0.211	0.083	0.064	0.053	0.094
10	0.035	0.250	0.168	0.321	0.098	0.088	0.084	0.119
11	0.058	0.284	0.255	0.468	0.133	0.176	0.214	0.176
12	0.090	0.339	0.308	0.595	0.193	0.238	0.228	0.229
13	0.130	0.386	0.354	0.773	0.286	0.281	0.269	0.284
14	0.174	0.476	0.406	0.955	0.394	0.326	0.308	0.349
15	0.227	0.558	0.444	1.160	0.504	0.358	0.362	0.412
16	0.292	0.669	0.492	1.274	0.623	0.402	0.413	0.489
17	0.376	0.761	0.542	1.372	0.738	0.442	0.453	0.565
18	0.459	0.870	0.594	1.454	0.851	0.477	0.496	0.642
19	0.565	0.992	0.643	1.526	0.957	0.525	0.531	0.727
20	0.699	1.095	0.689	1.591	1.251	0.570	0.727	0.837

CUM. BCF GAS PROD. PER COMMITTED WELL

YR	NGP - WILLIS.	ROCKY MTN.	OTHER WESTERN	S.W. APPR.	OTHER S.W.	EASTERN	MID CONT.	TOTAL U.S.
1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	0.001	0.049	0.005	0.005	0.010	0.001	0.001	0.013
5	0.002	0.079	0.015	0.012	0.023	0.005	0.002	0.022
6	0.005	0.109	0.027	0.020	0.038	0.009	0.005	0.032
7	0.007	0.132	0.039	0.034	0.049	0.010	0.010	0.035
8	0.010	0.153	0.049	0.056	0.057	0.017	0.017	0.045
9	0.013	0.169	0.063	0.087	0.065	0.025	0.023	0.056
10	0.019	0.188	0.081	0.126	0.074	0.036	0.032	0.069
11	0.027	0.208	0.105	0.172	0.087	0.053	0.044	0.087
12	0.039	0.232	0.131	0.222	0.108	0.075	0.056	0.109
13	0.054	0.256	0.158	0.277	0.138	0.098	0.071	0.134
14	0.072	0.289	0.184	0.335	0.174	0.121	0.086	0.160
15	0.092	0.323	0.210	0.395	0.216	0.144	0.103	0.188
16	0.114	0.360	0.236	0.455	0.262	0.167	0.121	0.218
17	0.137	0.399	0.261	0.514	0.310	0.190	0.138	0.249
18	0.163	0.439	0.287	0.570	0.359	0.213	0.157	0.281
19	0.190	0.480	0.312	0.624	0.410	0.235	0.175	0.313
20	0.220	0.521	0.337	0.676	0.465	0.258	0.196	0.347

TABLE E-15 (Continued)
Reserves Per Committed Well Scenario Summary
(Twice-Standard Scenario)

ANNUAL BCF RESERVES ADDED PER COMMITTED WELL

YR	NGP - WILLIS.	ROCKY MTN.	OTHER WESTERN	S.W. APPR.	OTHER S.W.	EASTERN	MID CONT.	TOTAL U.S.
1	1.145	3.511	0.883	1.231	1.702	0.798	0.562	1.596
2	1.081	1.962	0.888	1.600	1.702	0.823	0.589	1.207
3	1.095	1.869	0.895	1.805	1.878	0.835	0.578	1.229
4	1.013	1.936	0.888	2.303	1.828	0.638	0.576	1.230
5	1.064	1.997	1.026	2.352	1.869	0.933	0.589	1.271
6	1.078	1.957	1.039	2.517	1.669	0.967	0.610	1.289
7	1.187	1.889	1.102	2.160	1.678	0.915	0.609	1.158
8	1.235	1.823	1.113	2.423	1.767	1.039	0.615	1.354
9	1.283	1.767	1.102	2.418	1.941	1.060	0.715	1.399
10	1.298	1.727	1.097	2.359	2.073	1.096	0.785	1.428
11	1.288	1.701	1.221	2.361	2.213	1.268	1.144	1.541
12	1.282	1.681	1.262	2.361	2.269	1.282	1.140	1.549
13	1.271	1.631	1.247	2.368	2.318	1.294	1.149	1.538
14	1.262	1.614	1.252	2.371	2.367	1.289	1.153	1.534
15	1.262	1.582	1.242	2.380	2.414	1.297	1.153	1.533
16	1.266	1.568	1.242	2.380	2.414	1.293	1.153	1.532
17	1.271	1.554	1.242	2.380	2.414	1.285	1.153	1.531
18	1.263	1.541	1.242	2.380	2.414	1.297	1.153	1.532
19	1.278	1.536	1.242	2.380	2.414	1.297	1.157	1.539
20	1.285	1.523	1.242	2.380	2.660	1.297	1.165	1.558

CUM. RESERVES ADDED PER COMMITTED WELL (BCF)

YR	NGP - WILLIS.	ROCKY MTN.	OTHER WESTERN	S.W. APPR.	OTHER S.W.	EASTERN	MID CONT.	TOTAL U.S.
1	1.145	3.511	0.883	1.231	1.702	0.798	0.562	1.596
2	1.100	2.705	0.885	1.440	1.702	0.813	0.580	1.380
3	1.097	2.332	0.889	1.586	1.775	0.823	0.579	1.313
4	1.056	2.186	0.888	1.910	1.793	0.830	0.578	1.280
5	1.059	2.130	0.929	2.080	1.814	0.871	0.581	1.277
6	1.068	2.081	0.962	2.235	1.765	0.904	0.588	1.281
7	1.121	2.027	0.999	2.210	1.736	0.910	0.592	1.230
8	1.165	1.975	1.026	2.261	1.746	0.934	0.596	1.261
9	1.200	1.920	1.041	2.292	1.803	0.957	0.619	1.292
10	1.225	1.876	1.051	2.303	1.876	0.981	0.641	1.321
11	1.239	1.840	1.074	2.311	1.953	1.017	0.674	1.358
12	1.247	1.811	1.098	2.317	2.015	1.048	0.707	1.388
13	1.251	1.780	1.116	2.322	2.065	1.075	0.737	1.409
14	1.253	1.757	1.131	2.326	2.109	1.097	0.763	1.424
15	1.254	1.735	1.142	2.330	2.147	1.117	0.787	1.436
16	1.255	1.717	1.151	2.334	2.177	1.132	0.808	1.446
17	1.257	1.701	1.158	2.337	2.201	1.145	0.827	1.453
18	1.257	1.686	1.165	2.339	2.220	1.157	0.843	1.460
19	1.259	1.676	1.170	2.342	2.237	1.167	0.859	1.466
20	1.260	1.666	1.175	2.344	2.265	1.176	0.870	1.471

TABLE E-15 (Continued)
Production Rate vs. Remaining Reserves
(Twice-Standard Scenario)

REMAINING BCF RESERVES = CUM. RES - CUM. PROD

YR	NGP - WILLISTON	ROCKY MOUNTAINS	OTHER WESTERN	SOUTHWEST APPRAISED	OTHER SOUTHWEST	EASTERN	MID CONTINENT	TOTAL U.S.
1	76.700	1263.800	353.900	88.600	362.600	312.200	30.900	2488.700
2	243.200	2028.800	719.000	239.000	725.200	792.100	91.000	4838.297
3	569.400	3157.800	1093.000	439.400	1288.700	1527.500	195.700	8271.496
4	1070.221	4578.094	1489.371	962.194	1971.113	2833.914	327.140	13232.039
5	1827.587	6264.316	2179.614	1695.397	2729.199	4937.848	465.798	20099.754
6	3247.043	8391.090	3200.633	2817.620	3973.177	7712.520	619.426	29961.500
7	6131.551	11204.926	4455.492	4181.281	5816.734	10333.687	782.472	48906.145
8	10314.344	14657.980	5915.973	5562.844	8534.523	20586.062	944.602	66516.250
9	15040.586	18934.309	7451.566	6970.652	12428.504	25443.887	1190.828	87460.250
10	20572.012	23673.441	8931.805	8246.582	17605.992	31286.625	1413.470	111729.812
11	26463.109	28878.941	10335.305	9361.578	23625.156	36390.121	1562.405	136616.437
12	32571.602	34229.055	11831.422	10401.910	30077.566	41667.441	1733.919	162512.687
13	38727.867	39687.164	13310.117	11281.000	36452.395	47102.184	1904.698	188465.187
14	44783.039	44618.129	14728.180	12008.812	42696.121	52407.488	2071.313	213312.875
15	50525.398	49092.270	16100.051	12589.461	48795.344	57794.613	2227.188	237124.125
16	55711.812	52859.051	17390.633	13115.742	54514.668	62951.223	2373.049	258915.937
17	60211.516	56147.555	18594.316	13595.398	59866.441	67930.062	2510.922	278856.062
18	63963.656	58834.781	19709.379	14036.250	64857.645	72922.750	2640.343	296964.750
19	67023.687	60900.523	20739.945	14442.875	69510.937	77626.500	2765.708	313010.312
20	69272.437	62461.637	21691.484	14818.383	73310.375	82053.375	2834.477	326442.437

PERCENT BCF ANNUAL PROD / BCF REMAIN RES

YR	NGP - WILLIS.	ROCKY MTN.	OTHER WESTERN	S.W. APPR.	OTHER S.W.	EASTERN	MID CONT.	TOTAL U.S.
1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	0.063	2.291	0.512	0.240	0.537	0.176	0.110	0.993
5	0.177	2.163	1.283	0.448	0.920	0.447	0.331	1.109
6	0.322	2.641	1.808	0.553	1.282	0.710	0.625	1.385
7	0.393	2.861	1.913	0.969	1.421	0.636	1.029	1.360
8	0.455	3.038	2.044	1.345	1.403	0.909	1.394	1.515
9	0.561	3.194	2.428	1.931	1.400	1.217	1.669	1.724
10	0.748	3.382	2.988	2.437	1.460	1.623	1.900	1.981
11	1.043	3.618	3.587	2.947	1.634	2.265	2.187	2.351
12	1.418	3.950	4.080	3.370	1.999	2.893	2.468	2.767
13	1.811	4.264	4.411	3.775	2.461	3.201	2.736	3.111
14	2.165	4.628	4.615	4.089	2.920	3.422	2.925	3.425
15	2.486	4.968	4.747	4.386	3.299	3.559	3.202	3.690
16	2.784	5.309	4.863	4.624	3.650	3.695	3.428	3.942
17	3.070	5.626	5.015	4.804	3.937	3.845	3.558	4.178
18	3.348	5.926	5.181	4.930	4.190	3.984	3.703	4.399
19	3.614	6.182	5.331	5.028	4.396	4.115	3.838	4.593
20	3.870	6.406	5.461	5.110	4.600	4.231	4.027	4.773

TABLE E-15 (Continued)

Investment Committment Scenario Summary
(Twice-Standard Scenario)

MM-DOLLARS INVESTMENT COMMITTED ANNUALLY

YR	NGP - WILLIS.	ROCKY MTN.	OTHER WESTERN	S.W. APPR.	OTHER S.W.	EASTERN	MID CONT.	TOTAL U.S.
1	21.	439.	236.	49.	186.	215.	21.	1166.
2	47.	395.	249.	78.	186.	326.	36.	1319.
3	97.	592.	255.	103.	288.	481.	65.	1880.
4	165.	795.	286.	257.	349.	821.	77.	2750.
5	257.	968.	448.	354.	387.	1259.	80.	3752.
6	515.	1374.	763.	521.	654.	1699.	85.	5612.
7	1085.	2026.	932.	658.	968.	6215.	92.	11975.
8	1597.	2749.	1166.	680.	1391.	2672.	93.	10347.
9	1861.	3624.	1303.	718.	1895.	3122.	148.	12670.
10	2204.	4201.	1328.	694.	2443.	3740.	132.	14742.
11	2402.	4890.	1422.	656.	2845.	3273.	91.	15578.
12	2560.	5349.	1586.	656.	3144.	3570.	107.	16972.
13	2670.	5697.	1663.	619.	3254.	3811.	110.	18029.
14	2748.	5826.	1682.	581.	3365.	3900.	111.	18212.
15	2742.	5930.	1712.	543.	3475.	4059.	111.	18574.
16	2641.	5737.	1712.	543.	3475.	4090.	111.	18310.
17	2475.	5701.	1712.	543.	3475.	4160.	111.	18178.
18	2300.	5515.	1712.	543.	3475.	4281.	111.	17939.
19	2123.	5240.	1712.	543.	3475.	4281.	113.	17487.
20	1911.	5077.	1712.	543.	3153.	4281.	82.	16760.

CUM. MM-DOLLARS INVESTMENT COMMITTED

YR	NGP - WILLIS.	ROCKY MTN.	OTHER WESTERN	S.W. APPR.	OTHER S.W.	EASTERN	MID CONT.	TOTAL U.S.
1	21.	439.	236.	49.	186.	215.	21.	1166.
2	68.	834.	485.	127.	372.	540.	59.	2485.
3	165.	1426.	739.	230.	660.	1021.	124.	4365.
4	330.	2221.	1026.	487.	1009.	1842.	201.	7115.
5	587.	3188.	1473.	841.	1396.	3101.	281.	10867.
6	1102.	4562.	2237.	1362.	2051.	4801.	366.	16479.
7	2187.	6588.	3168.	2020.	3018.	11016.	458.	28454.
8	3784.	9337.	4334.	2699.	4409.	13686.	550.	38801.
9	5645.	12961.	5636.	3417.	6305.	16810.	698.	51471.
10	7849.	17161.	6964.	4111.	8748.	20549.	830.	66213.
11	10251.	22052.	8386.	4767.	11593.	23823.	920.	81791.
12	12810.	27401.	9971.	5423.	14736.	27393.	1028.	98763.
13	15486.	33298.	11634.	6041.	17991.	31204.	1138.	116792.
14	18234.	39124.	13316.	6622.	21355.	35104.	1249.	135004.
15	20976.	45054.	15028.	7166.	24831.	39163.	1360.	153578.
16	23617.	50792.	16740.	7709.	28306.	43252.	1471.	171888.
17	26092.	56493.	18452.	8252.	31782.	47412.	1582.	190066.
18	28393.	62008.	20164.	8790.	35257.	51693.	1694.	208004.
19	30516.	67248.	21877.	9339.	38732.	55974.	1806.	225492.
20	32427.	72325.	23589.	9882.	41885.	60255.	1888.	242251.

TABLE E-15 (Continued)

Cash Flow Scenario Summary
(Twice-Standard Scenario)

ANNUAL CASH FLOW MM-DOLLARS

YR	NGP - WILLISTON	ROCKY MOUNTAINS	OTHER WESTERN	SOUTHWEST APPRAISED	OTHER SOUTHWEST	EASTERN	MID CONTINENT	TOTAL U.S.
1	-0.446	-1.473	-0.677	-0.291	-1.420	-0.837	-0.056	-5.200
2	-3.143	-22.868	-9.557	-2.056	-7.039	-8.797	-0.975	-54.434
3	-8.491	-110.512	-25.836	-9.545	-38.397	-27.327	-2.525	-228.633
4	-14.875	145.393	-23.413	-18.842	-41.731	-41.115	-6.848	-1.432
5	-25.672	110.846	-29.771	-25.460	-48.520	-81.306	-10.973	-110.855
6	-36.950	235.911	9.531	-49.332	-20.247	-91.583	-14.374	32.956
7	-62.850	362.966	37.606	-34.473	19.066	-109.818	-12.830	199.667
8	-116.446	495.424	55.588	-12.888	55.641	-165.358	-9.923	302.038
9	-184.936	672.383	99.813	82.623	92.530	-177.684	-1.209	583.517
10	-197.942	865.386	196.612	182.665	139.603	184.339	8.125	1378.187
11	-162.609	1091.575	333.550	319.727	211.512	-71.865	17.898	1739.788
12	-33.421	1478.736	515.651	468.370	430.747	814.658	28.454	3703.195
13	265.225	1954.451	705.134	629.660	826.927	1388.530	42.415	5812.336
14	642.384	2536.343	874.645	769.525	1390.055	2017.449	63.222	8293.617
15	1091.243	3168.642	1029.541	906.205	2031.588	2592.350	86.140	10905.695
16	1585.849	3824.784	1173.545	1033.428	2746.702	3076.897	106.667	13547.859
17	2117.753	4481.988	1320.288	1145.535	3449.004	3606.724	121.839	16243.121
18	2672.452	5153.305	1489.597	1239.250	4179.500	4173.898	138.054	19046.043
19	3237.877	5776.652	1653.267	1320.881	4879.141	4736.293	154.318	21758.422
20	3796.136	6332.060	1810.893	1394.186	5547.812	5302.703	170.066	24354.445

CUMULATIVE MM-DOLLARS CASH FLOW

YR	NGP - WILLISTON	ROCKY MOUNTAINS	OTHER WESTERN	SOUTHWEST APPRAISED	OTHER SOUTHWEST	EASTERN	MID CONTINENT	TOTAL U.S.
1	-0.446	-1.473	-0.677	-0.291	-1.420	-0.837	-0.056	-5.200
2	-3.588	-24.341	-10.234	-2.347	-8.459	-9.635	-1.031	-59.635
3	-12.079	-140.853	-36.071	-11.892	-46.856	-36.961	-3.556	-288.268
4	-26.954	4.540	-59.483	-30.734	-88.587	-78.077	-10.405	-289.699
5	-52.626	115.387	-89.254	-56.195	-137.107	-159.382	-21.378	-400.554
6	-89.576	351.298	-79.723	-105.527	-157.353	-250.965	-35.752	-367.597
7	-152.426	714.264	-42.117	-139.999	-138.287	-360.783	-48.581	-167.930
8	-268.872	1209.688	13.472	-152.888	-82.646	-526.141	-58.504	134.108
9	-453.810	1882.071	113.285	-70.265	9.883	-703.825	-59.713	717.625
10	-651.751	2747.458	309.896	112.400	148.886	-519.486	-51.589	2095.812
11	-814.360	3839.033	643.447	432.128	360.399	-591.351	-33.691	3835.600
12	-847.781	5317.766	1159.097	900.498	791.146	223.308	-5.238	7538.793
13	-582.556	7272.215	1864.231	1530.158	1618.073	1611.837	37.177	13351.129
14	59.828	9608.555	2738.876	2299.684	3008.128	3629.287	100.399	21644.746
15	1151.070	12977.195	3768.417	3205.889	5039.715	6221.633	186.539	32550.441
16	2736.919	16801.977	4941.961	4239.316	7786.414	9298.527	293.206	46098.301
17	4854.672	21283.965	6262.246	5384.852	11235.418	12905.250	415.045	62341.422
18	7527.121	26437.270	7751.840	6624.098	15414.918	17079.148	553.099	81387.437
19	10764.996	32213.922	9405.106	7944.977	20294.059	21815.441	707.416	103145.812
20	14561.129	38546.582	11215.996	9339.160	25841.871	27118.145	877.482	127500.250

TABLE E-15 (Continued)

Investment Per Committed Wells Scenario Summary
(Twice-Standard Scenario)

ANNUAL MM-DOLLARS PER WELL (COMMITTED)

YR	NGP - WILLIS.	ROCKY MTN.	OTHER WESTERN	S.W. APPR.	OTHER S.W.	EASTERN	MID CONT.	TOTAL U.S.
1	0.310	1.220	0.588	0.681	0.873	0.549	0.382	0.748
2	0.305	1.014	0.606	0.834	0.873	0.558	0.371	0.677
3	0.326	0.960	0.609	0.924	0.961	0.545	0.359	0.673
4	0.334	1.008	0.629	1.127	0.920	0.525	0.337	0.664
5	0.359	1.061	0.640	1.123	0.924	0.553	0.335	0.673
6	0.388	1.145	0.735	1.152	0.843	0.581	0.331	0.704
7	0.443	1.221	0.766	1.012	0.843	0.652	0.326	0.707
8	0.466	1.286	0.820	1.131	0.866	0.625	0.326	0.753
9	0.496	1.311	0.837	1.125	0.904	0.640	0.397	0.789
10	0.503	1.310	0.854	1.108	0.932	0.645	0.415	0.795
11	0.502	1.331	0.978	1.114	0.983	0.700	0.566	0.854
12	0.499	1.342	1.011	1.114	1.011	0.706	0.570	0.865
13	0.496	1.345	1.003	1.123	1.037	0.710	0.566	0.872
14	0.494	1.344	1.003	1.130	1.063	0.708	0.564	0.869
15	0.495	1.357	0.995	1.141	1.088	0.707	0.564	0.874
16	0.496	1.369	0.995	1.141	1.088	0.707	0.564	0.877
17	0.496	1.374	0.995	1.141	1.088	0.704	0.564	0.881
18	0.493	1.377	0.995	1.141	1.088	0.703	0.564	0.882
19	0.495	1.381	0.995	1.141	1.088	0.703	0.563	0.885
20	0.498	1.390	0.995	1.141	1.169	0.703	0.523	0.900

CUM. MM-DOLLARS PER WELL (COMMITTED)

YR	NGP - WILLIS.	ROCKY MTN.	OTHER WESTERN	S.W. APPR.	OTHER S.W.	EASTERN	MID CONT.	TOTAL U.S.
1	0.310	1.220	0.588	0.681	0.873	0.549	0.382	0.748
2	0.306	1.113	0.597	0.767	0.873	0.555	0.375	0.709
3	0.318	1.053	0.601	0.830	0.910	0.550	0.366	0.693
4	0.325	1.037	0.609	0.964	0.913	0.539	0.354	0.682
5	0.339	1.044	0.618	1.025	0.916	0.544	0.349	0.679
6	0.361	1.072	0.653	1.070	0.892	0.557	0.344	0.687
7	0.397	1.114	0.683	1.051	0.875	0.607	0.340	0.695
8	0.424	1.160	0.715	1.070	0.872	0.610	0.338	0.710
9	0.445	1.199	0.740	1.081	0.882	0.616	0.349	0.728
10	0.460	1.224	0.756	1.085	0.895	0.621	0.358	0.742
11	0.469	1.246	0.786	1.089	0.915	0.631	0.371	0.761
12	0.475	1.264	0.815	1.092	0.934	0.640	0.385	0.777
13	0.478	1.277	0.838	1.095	0.951	0.647	0.398	0.790
14	0.481	1.287	0.856	1.098	0.967	0.654	0.408	0.800
15	0.482	1.296	0.870	1.101	0.983	0.659	0.418	0.808
16	0.484	1.304	0.881	1.104	0.994	0.663	0.426	0.815
17	0.485	1.310	0.890	1.107	1.004	0.666	0.434	0.821
18	0.486	1.316	0.898	1.109	1.012	0.669	0.440	0.826
19	0.486	1.321	0.905	1.110	1.018	0.672	0.446	0.830
20	0.487	1.325	0.911	1.112	1.028	0.674	0.449	0.835

TABLE E-15 (Continued)

Investment/Reserves Ratio Scenario Summary
(Twice-Standard Scenario)

ANNUAL MM-DOLLARS COMMITTED PER BCF RESERVES

YR	NGP - WILLIS.	ROCKY MTN.	OTHER WESTERN	S.W. APPR.	OTHER S.W.	EASTERN	MID CONT.	TOTAL U.S.
1	0.271	0.347	0.667	0.553	0.513	0.688	0.680	0.469
2	0.282	0.517	0.682	0.521	0.513	0.678	0.629	0.561
3	0.296	0.524	0.681	0.512	0.512	0.653	0.620	0.548
4	0.329	0.521	0.708	0.489	0.503	0.626	0.586	0.540
5	0.338	0.531	0.623	0.477	0.494	0.592	0.569	0.529
6	0.360	0.585	0.707	0.458	0.505	0.601	0.542	0.546
7	0.373	0.646	0.695	0.469	0.502	0.712	0.535	0.611
8	0.377	0.705	0.737	0.467	0.490	0.602	0.529	0.556
9	0.387	0.742	0.759	0.465	0.466	0.604	0.555	0.564
10	0.388	0.758	0.760	0.470	0.450	0.589	0.529	0.557
11	0.389	0.782	0.801	0.472	0.444	0.562	0.495	0.554
12	0.390	0.798	0.801	0.472	0.446	0.561	0.500	0.558
13	0.390	0.825	0.805	0.474	0.447	0.549	0.493	0.567
14	0.391	0.833	0.802	0.477	0.449	0.549	0.489	0.566
15	0.392	0.858	0.802	0.480	0.451	0.545	0.489	0.570
16	0.392	0.873	0.802	0.480	0.451	0.547	0.489	0.572
17	0.390	0.884	0.802	0.480	0.451	0.548	0.489	0.575
18	0.390	0.893	0.802	0.480	0.451	0.542	0.489	0.575
19	0.387	0.899	0.802	0.480	0.451	0.542	0.486	0.575
20	0.388	0.913	0.802	0.480	0.440	0.542	0.449	0.578

CUM. MM-DOLLARS COMMITTED PER BCF RESERVES

YR	NGP - WILLIS.	ROCKY MTN.	OTHER WESTERN	S.W. APPR.	OTHER S.W.	EASTERN	MID CONT.	TOTAL U.S.
1	0.271	0.347	0.667	0.553	0.513	0.688	0.680	0.469
2	0.278	0.411	0.674	0.533	0.513	0.682	0.646	0.514
3	0.289	0.452	0.677	0.523	0.512	0.668	0.632	0.528
4	0.306	0.474	0.685	0.505	0.509	0.649	0.613	0.532
5	0.320	0.490	0.685	0.493	0.505	0.625	0.600	0.531
6	0.338	0.515	0.679	0.479	0.505	0.616	0.586	0.536
7	0.354	0.550	0.684	0.475	0.504	0.667	0.575	0.565
8	0.364	0.588	0.697	0.473	0.500	0.653	0.566	0.563
9	0.371	0.624	0.711	0.472	0.489	0.643	0.564	0.563
10	0.376	0.652	0.719	0.471	0.477	0.633	0.558	0.562
11	0.379	0.677	0.732	0.471	0.469	0.620	0.551	0.560
12	0.381	0.698	0.742	0.471	0.464	0.610	0.545	0.560
13	0.382	0.717	0.751	0.472	0.461	0.602	0.540	0.561
14	0.384	0.733	0.757	0.472	0.459	0.596	0.535	0.562
15	0.385	0.747	0.762	0.473	0.458	0.590	0.531	0.563
16	0.386	0.759	0.765	0.473	0.457	0.586	0.527	0.564
17	0.386	0.770	0.769	0.474	0.456	0.582	0.525	0.565
18	0.386	0.780	0.771	0.474	0.456	0.579	0.522	0.566
19	0.386	0.788	0.774	0.474	0.455	0.576	0.520	0.566
20	0.386	0.796	0.776	0.475	0.454	0.573	0.516	0.567

APPENDIX F

Federal Land Withdrawal

THE NATIONAL WILDERNESS PRESERVATION SYSTEM

Over the past years, the U.S. Congress has designated certain lands to be set aside as part of the National Wilderness Preservation System. This system contains land administered by the U.S. Forest Service, the National Park Service, and the Fish and Wildlife Service. In recent years, two major review programs have been initiated with the purpose of identifying additional lands for inclusion in the national wilderness preservation system. These are the BLM Wilderness Review program and the Forest Service Roadless Area Review and Evaluation II (RARE II) program.

Those areas already designated wildernesses as of November 1978 (not associated with the Bureau of Land Management [BLM] or recent Forest Service programs) are shown in Figures F-1 and F-2. Also, Table F-1 summarizes the extent of the existing and proposed National Wilderness Preservation System.

A study of wilderness and prospective wilderness areas in relation to tight gas prospective areas is important because oil and gas exploration and development will be restricted in wilderness areas. A discussion of the BLM and Forest Service review programs follows.

Major Federal Land Withdrawal Programs

BLM Wilderness Study Areas

The BLM wilderness study program is in response to the Federal Land Policy and Management Act of 1976 (FLPMA).

- Phase 1A: Initial Inventory

  Beginning in the fall of 1978, all public domain land administered by the U.S. Bureau of Land Management was studied by the various Bureau of Land Management state offices. This initial inventory resulted in classifying approximately 70 percent (122.8 million acres) of the land in the contiguous western states as nonwilderness and therefore open to multiple resource use, including oil and gas exploration and development.

- Phase 1B: Intensive Inventory

  The land classified as having possible wilderness characteristics in the initial inventory phase will undergo more intensive study to determine if it truly meets all of the requirements of classification as a wilderness area. These intensive inventories were begun by the various state BLM

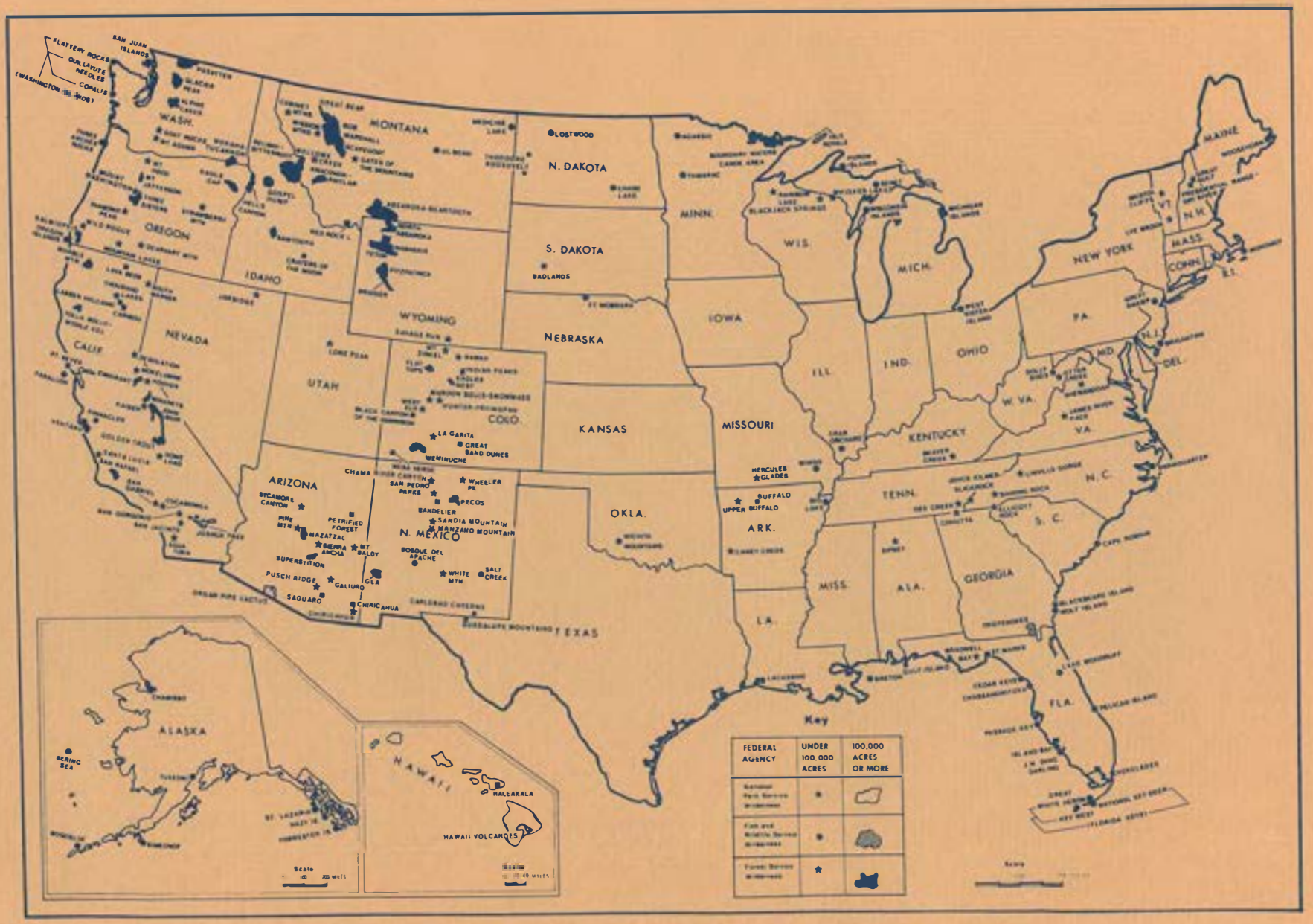


Figure F-1. National Wilderness Preservation System November 1, 1978.

SOURCE: Rare II Final Environmental Statement, *U.S. Forest Service*, January 1979.

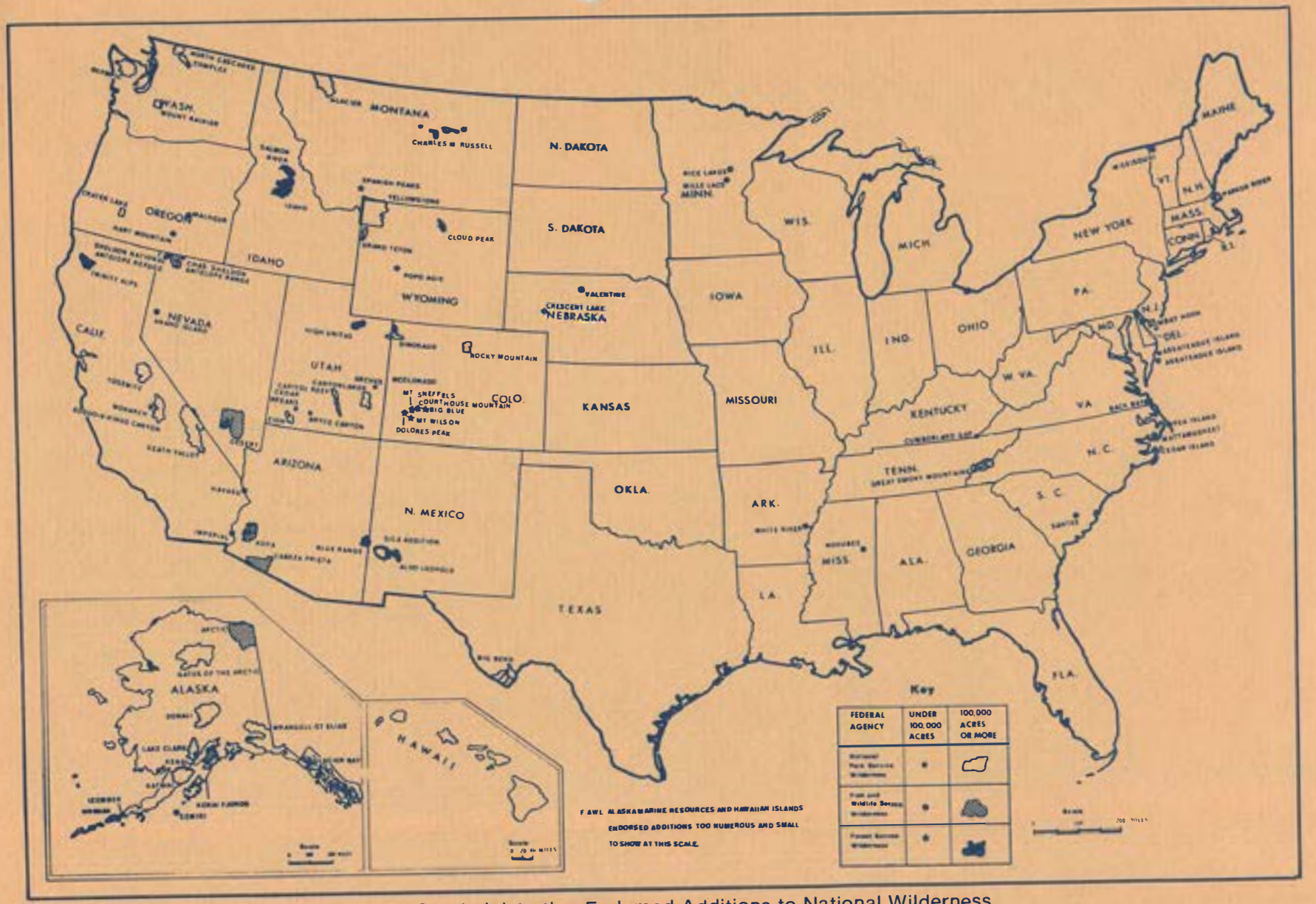


Figure F-2. Administration Endorsed Additions to National Wilderness Preservation System November 1, 1978.

SOURCE: Rare II Final Environmental Statement, *U.S. Forest Service*, January 1979.

TABLE F-1

National Wilderness Preservation System -- 1979
(Wilderness Area - Millions of Acres)

Type of Wilderness	BLM	Forest Service	Park Service	Wildlife Refuges
Existing	-	15.2	3.0	0.8
Administratively Endorsed	-	3.3	12.7	7.2
Subtotal	0	18.5	15.7	8.0
Additional Proposed Wilderness Areas (BLM and Forest RARE II)	20.8	15.1	-	-
Further Planning Areas (Potential Wilderness)	-	10.8	-	-
Total	20.8	44.4	15.7	8.0

Source: RARE II Final Environmental Statement, U.S. Forest Service, Janaury 1979, and Oil and Gas Journal, April 1980.

offices in the summer of 1979 and several had been completed by April 1980. The inventories will identify those areas which should undergo more detailed study and be designated as wilderness study areas (WSA). When these inventories are complete, proposed WSA areas will be subject to a 90-day comment period by the public. Then, each state BLM director will designate those areas to undergo the WSA wilderness study. As of May 1980, inventory studies were essentially complete. Results for selected states are shown in Table F-2. As one example, the Utah inventory study report was issued on April 2, 1980. Of the 22.08 million acres subjected to both the initial and intense inventories, 1.75 million acres were proposed as truly having wilderness characteristics and will undergo the more detailed WSA study. When the WSA detailed study is complete, the various state BLM directors will make recommendations to the President and the U.S. Congress on which of the areas should be classified as wilderness and therefore included in the National Wilderness Preservation System. These more intensive WSA studies are required to be complete by 1991. One state BLM official estimates that his state WSA studies will be completed by 1985-1986. It is in this final study phase that the oil and gas potential of the proposed wilderness areas will be evaluated in detail.

Special Instant or Accelerated Study Areas (BLM Review Program)

Certain acreage designated in the initial inventory as having possible wilderness characteristics will undergo more rapid or accelerated study. These areas are the ones with special use or benefit characteristics, such as sites of coal-fired electric power plants and oil and gas areas of the Overthrust Belt in several western states. As of January 1980 some of these areas had already been designated as wilderness study areas and were recommended for more detailed evaluation. This acreage totaled about 9.98 million acres for the entire United States and 0.93 million acres for the states shown in Table F-2.

RARE II Wilderness Areas -- U.S. Forest Service, Department of Agriculture

The RARE II wilderness review program was initiated in June 1977 to identify roadless and underdeveloped land areas in the national forest system and to determine their general use for both wilderness and other resource management and development. The review identified 2,919 roadless areas containing 62 million acres in the national forest and grasslands in 38 states and Puerto Rico. The review was completed in the fall of 1977 after massive involvement by the public. More than 50,000 persons responded with comments and suggestions. Results of the review were presented by the U.S. Forest Service in a draft environmental statement issued on June 15, 1978. The public was asked to comment on this statement also, and final classification recommendations were as follows (see Table F-3 for data on selected western states):

[1]Wilderness Classifications	15.09 million acres
Nonwilderness Classifications	36.15 million acres
Further Planning	10.77 million acres
Total United States	62.01

National Parks

In the national park system there are currently about 25 areas classified as wilderness, totaling about 3 million acres. The Park Service has studied the remaining undeveloped park land and has wilderness proposals pending action by Congress. If all endorsed areas are classified wilderness, there would be a total of 45 park wilderness areas containing more than 15.7 million acres. There are additional national park areas not yet studied that could raise this acreage slightly.

Wildlife Refuges -- Wilderness Areas

Congress has designated 52 units of the National Wildlife Refuge System with approximately 771,000 acres as wilderness. An additional 33 areas containing 7.2 million acres have been endorsed by the President and are pending before Congress. Several large areas are still under study and may result in significant increases.

[1]Source: RARE II Final Environmental Statement, U.S. Forest Service, January 1979.

Table F-2

U.S. Bureau of Land Management -
Wilderness Study Area (WSA) Acreage - Selected Western States
(Thousands of Acres)

	Total Acres Inventoried	Acres Proposed WSA's	Acres Designated As Instant or Accelerated WSA	Total WSA Acres	Proposed WSA's As Percentage of Total Acres Inventoried
Colorado	7,996	765	50	815	9.6
Montana	8,140	534	249	783	6.6
New Mexico	12,847	872	148	1,020	6.8
North Dakota	68	0	0	0	0
Utah	22,076	1,752	427	2,179	7.9
Wyoming	17,793	497	56	553	2.8
Total	68,920	4,420	930	5,350	6.4

Source: Oil & Gas Journal, April 1980.

Table F-3

U.S. Forest Service - Rare II Wilderness Area Acreage - Selected Western Service
(Thousands of Acres)

	Total Acres Inventoried	Acres Proposed As Wilderness	Acres Designated Further Planning	Acres Dropped Non wilderness	Total Wilderness and Further Plan.	Wilderness and Further Planning as % of Total
Colorado	6,493.2	1,946.4	177.6	4,369.2	2,124.0	32.7
Montana	5,050.6	599.9	1,185.8	3,264.9	1,785.7	35.4
New Mexico	1,907.4	497.2	256.9	1,153.3	754.1	39.5
North Dakota	194.7	9.0	0	185.7	9.0	4.6
Utah	3,002.4	492.1	138.4	2,371.9	630.5	21.0
Wyoming	3,794.5	627.1	338.8	2,828.6	965.9	25.5
Total	20,442.8	4,171.7	2,097.5	14,173.6	6,269.2	30.7

Source: RARE II Final Environmental Statement, U.S. Forest Service, Jan. 1979.

APPENDIX G

FERC Ruling on Tight Gas

Federal Energy Regulatory Commission
Final Ruling on High-Cost Natural Gas
Produced From Tight Formations

1. Part 271 is amended in Table of Contents under Subpart G to read as follows:

SUBPART G -- HIGH-COST NATURAL GAS

Sec.
271.701 Applicability.
271.702 General rules.
271.703 Tight formations.

2. Subpart G of Part 271 is revised to read as follows:

SUBPART G -- HIGH-COST NATURAL GAS

§ 271.701 Applicability

This subpart implements section 107(b) and (c) of the NGPA and applies to the first sale of natural gas which a jurisdictional agency determines is:

(a) Tight formation gas for which there is a negotiated contract price.

(b) [Reserved]

§ 271.702 General rules.

(a) Definitions. For purposes of this subpart:

(1) "Negotiated contract price" means any price established by a contract which either specifically references the incentive pricing authority of the Commission under section 107 of the NGPA or contains a fixed rate or a fixed escalator clause.

(2) A "fixed escalator clause" is a provision in a contract for the first sale of natural gas which changes the price for the gas by a specified amount on a specified date.

(3) For the definition of "crude oil," see §270.102(b)(5).

(b) Cross reference. For special rules applicable to high-cost natural gas retroactive collections, see §273.204.

§ 271.703 Tight formations.

(a) Maximum lawful price for tight formation gas. The maximum lawful price, per MMBtu, for the first sale of tight formation gas for which there is a negotiated contract price shall be the lesser of:

(i) the negotiated contract price; or

(ii) 200 percent of the maximum lawful price specified for Subpart C of Part 271 in Table I of § 271.101(a).

(b) Definitions.

(1) "Tight formation gas" means new tight formation gas or recompletion tight formation gas.

(2) "New tight formation gas" is natural gas:

(i) which is new natural gas, (as defined in section 102(c)), certain OCS gas qualifying for the new natural gas ceiling price (as defined in section 102(d)), or gas produced through a new onshore production well (as defined in section 103(c)); and

(ii) which is produced from a designated tight formation through a well the surface drilling of which began on or after July 16, 1979.

(3) "Recompletion tight formation gas" is natural gas which is produced from a designated tight formation through a well, the surface drilling of which was begun before July 16, 1979, if such well was not completed for production from such designated formation before July 16, 1979.

(4) "Formation" means any geological formation, or portion thereof described by geological as well as geographical parameters.

(5) A "designated tight formation" is a natural gas formation which is designated a tight formation by the Commission pursuant to paragraph (c) of this section.

(6) "Infill drilling" means any drilling in a substantially developed formation (or a portion thereof) subject to requirements respecting well-spacing or proration units which were amended by the jurisdictional agency after the formation (or portion thereof) was substantially developed and which were adopted for the purpose of more effective and efficient drainage of the reservoirs in such formation. Such amendment may provide for the establishment of smaller drilling or production units or may permit the drilling of additional wells on the original units.

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(c) Designation of tight formations.

(1) General. Upon the written recommendation by a jurisdictional agency, submitted in accordance with the requirements of this section, the Commission may approve a recommendation that a natural gas formation be designated as a tight formation.

(2) Guidelines. (i) The Commission will approve the designation of any formation recommended by a jurisdictional agency if the formation meets each of the following guidelines:

(A) The estimated average in situ gas permeability, throughout the pay section, is expected to be 0.1 millidarcy or less.

(B) The stabilized production rate, against atmospheric pressure, of wells completed for production in the formation, without stimulation, is not expected to exceed the production rate determined in accordance with the following table:

If the average depth to the top of the formation (in feet)		The maximum allowable production rate (in Mcf/day) may not exceed:
exceeds:	but does not exceed:	
0	1000	44
1000	1500	51
1500	2000	59
2000	2500	68
2500	3000	79
3000	3500	91
3500	4000	105
4000	4500	122
4500	5000	141
5000	5500	163
5500	6000	188
6000	6500	217

If the average depth to the top of the formation (in feet) exceeds:	but does not exceed:	The maximum allowable production rate (in Mcf/day) may not exceed:
6500	7000	251
7000	7500	290
7500	8000	336
8000	8500	388
8500	9000	449
9000	9500	519
9500	10000	600
10000	10500	693
10500	11000	802
11000	11500	927
11500	12000	1071
12000	12500	1238
12500	13000	1432
13000	13500	1655
13500	14000	1913
14000	14500	2212
14500	15000	2557

(C) No well drilled into the recommended tight formation is expected to produce, without stimulation, more than five barrels of crude oil per day.

(D) If the formation or any portion thereof was authorized to be developed by infill drilling prior to the date of recommendation and the jurisdictional agency has information which in its judgment indicates that such formation or portion subject to infill drilling can be developed absent the incentive price established in paragraph (a) of this section then the jurisdictional agency shall not include such formation or portion thereof in its recommendation.

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(ii) The Commission will consider and may approve or disapprove a recommendation by a jurisdictional agency to designate as a tight formation any formation which meets the guidelines contained in subparagraph (2)(i)(B) and (C), but does not meet the guideline contained in subparagraph (2)(i)(A), if the jurisdictional agency makes an adequate showing that the formation exhibits low permeability characteristics and the price established in paragraph (a) of this section is necessary to provide reasonable incentives for production of the natural gas from the recommended formation due to the extraordinary costs associated with such production.

(3) Content of recommendations. A recommendation that a formation should qualify as a designated tight formation shall contain the following information:

(i) geological and geographical descriptions of the formation which is recommended for classification as a tight formation;

(ii) geological and engineering data to support the recommendation and the source of that data;

(iii) a map which clearly locates wells which are currently producing from the recommended tight formation or a list locating all wells which are currently producing natural gas from the recommended tight formation;

(iv) a report of the extent to which existing State and Federal regulations will assure development of the recommended tight formation will not adversely affect any fresh water aquifers (during both hydraulic fracturing and waste disposal operations) that are or are expected to be used as a domestic or agricultural water supply;

(v) if the formation is recommended under paragraph (c)(2)(ii) of this section, the types and extent of enhanced production techniques which are expected to be necessary and the estimated expenditures necessary for employing those techniques; and the degree of increase in production to be expected from use of such techniques and engineering and geological data to support that estimate;

(vi) any other information which the jurisdictional agency deems relevant; and

(vii) any other information requested by the Commission.

(4) Commission review of recommendations. Upon receipt of a recommendation submitted in accordance with this section, the Commission shall publish in the Federal Register, a notice of proposed rulemaking containing such recommendation. After review of any comments, the Commission will prescribe a rule approving or disapproving the recommendation.

(d) Designated tight formations. [Reserved].

3. Section 273.204(a)(1) is amended by deleting "; and" in clause (i) and inserting in lieu thereof a period at the end of clause (i), and by deleting "new" in clause (ii) and by deleting the semi-colon and inserting in lieu thereof a period at the end of clause (ii).

4. Section 274.205 is amended by revising paragraph (e) to read as follows:

§ 274.205 High-cost natural gas.

* * * * *

(e) Natural gas produced from designated tight formations.

(1) New tight formation gas. A person seeking a determination for purposes of Subpart G of Part 271 that natural gas is new tight formation gas shall file with the jurisdictional agency an application which contains the following items:

(i)(A) If the gas is produced from a well which qualifies as a new, onshore production well, all information required in § 274.204 (except for the item specified in paragraph (d)(1) of that section); or

(B) if the gas qualifies for the new natural gas price, the information required in § 274.202 or § 274.203;

(ii) a map which locates and identifies the well for which the determination is sought as being within the designated tight formation;

(iii) the heading and pertinent portions of the well log, or a drilling report identifying the designated tight formation; and

(iv) a statement by the applicant, under oath, that:

(A) the surface drilling of the well for which a determination is sought was begun on or after July 16, 1979;

(B) the gas is being produced from a designated tight formation; and

(C) the applicant has no knowledge of any other information not described in the application which is inconsistent with his conclusions.

(2) Recompletion tight formation gas. A person seeking a determination for purposes of Subpart G of Part 271 that natural gas is recompletion tight formation gas shall file with the jurisdictional agency an application which contains the following items:

(i) the well completion report;

(ii) a map which locates and identifies the well for which the determination is sought as being within the designated tight formation;

(iii) the heading and pertinent portions of the well log, or a drilling report identifying the designated tight formation; and

(iv) a statement by the applicant, under oath, that:

(A) the gas is being produced from a designated tight formation;

(B) the well did not produce natural gas in commercial quantities from the designated tight formation prior to July 16, 1979; and

(C) the applicant has no knowledge of any other information not described in the application which is inconsistent with his conclusions.

APPENDIX H

Research Topics and Programs

RESEARCH TOPICS AND PROGRAMS

Enhancing technology for the development and recovery of gas from tight gas formations will require advancements in many specific disciplines of research. In addition, it will be necessary to combine the knowledge from a wide variety of disciplines to optimize the rate of advancement on the learning curve. The problems and needs associated with tight gas reservoirs have been identified and discussed in preceding portions of this chapter as well as in many of the previous chapters. This appendix presents topics and projects categorized by discipline which have a high potential for addressing specific requirements and contains a suggested comprehensive program approach for conducting and organizing the specific research to accelerate learning, integrate theory into practice, and transfer the technology for application.

SPECIFIC POTENTIAL AREAS AND TOPICS TO ENHANCE TIGHT GAS FORMATION DEVELOPMENT AND RECOVERY (Categorized by Discipline)

The specific research topics for each discipline have been presented in order of importance; topics with a higher potential for impact have been listed first. The ordering was determined by a ballot procedure. Each study participant was requested to furnish a list of essential research topics. These topics were then prioritized by weighted ballots from the study participants. This statement, however, must be qualified: the ordering is consistent with current views. As technology and experience advance, those topics which are considered less important may migrate to higher levels.

Geological Requirements

- Studies and techniques to ascertain the size, shape, and lithology of tight gas formation sand bodies
- Methods for determining the size, shape, and distribution of lenticular sand bodies
- Determination of the effect of lithology and rock type on in situ stresses
- Evaluation of sand continuity, and methods for determining sand continuity and the probable geometry of sand lenses
- Knowledge of source rock type and maturity and its effect on generating gas in low permeability formations
- Knowledge of geological transgressive and regressive cycles associated with low permeability gas formations

- Investigations of the geological conditions pertinent to the preservation of natural gas and its rate of escape from low permeability reservoirs

- Studies on the effectiveness of various seals for natural gas accumulation in tight reservoirs

- Studies on the time required for generation and expulsion of thermal and bacterial gases and carbonization stages during expulsion

- More accurate discrimination between thermal and bacterial gas

- Studies to ascertain the quantities of gas expelled from various types of source beds

- Evaluation of the significance of overpressured and underpressured tight gas reservoirs; pressure/temperature relationship; cause of disruption of hydropressured water columns in a subnormal pressure setting

- Studies on the effects of methane-consuming bacteria in the destruction of shallow hydrocarbon gas accumulations; i.e., conditions permitting bacterial viability and active methane consumption

- Determination of the role of fluid-pressure-induced natural fractures in controlling or influencing massive hydraulic fracturing treatments

- Knowledge of the influence of organic matter, natural gas liquids, adsorbed gases, nonhydrocarbon gases, water salinity, and composition on gas production from tight reservoirs.

Petrophysical Requirements

- Studies of the fracturing fluid/rock formation interactive mechanisms which may pertain to water blocking

- Improved laboratory methods for determining in situ rock properties

- Studies of the clay content and grain size of tight gas sands as they relate to the depositional environment of the formations

- Evaluation of the information which can be contributed by investigations of cores as it pertains to the tight formation gas-producing potential of a reservoir

- Studies of the effect of rock matrix and cementation on in situ permeability to gas.

Formation Evaluation, Well Logging, and Geophysical Requirements

- Development of wireline tools for measuring in situ stresses
- Development of improved geophysical exploration tools for tight gas formation exploration
- Development of surface geophysical methods for in situ measurement of rock stress from a well bore
- Improved geophysical methods for identifying lenticular sands that have not been penetrated by a well but may possibly be reached by a hydraulic fracture
- Improved geophysical methods for the determination of closure stress
- Evaluation of the reliability of drill stem tests for determining tight gas formation potential
- Improved methods for measuring and interpreting water saturations
- Development of logging methods for improved in situ permeability measurement
- Calibration studies of the relationship between core analysis data with log in situ property measurements
- Improved methods to measure and interpret fracture orientation with logging tools
- Improved abilities to measure and interpret gas in place
- Improved log correlations with an analysis of porosity
- Improved abilities to measure and interpret in situ permeability from logs
- Studies on the correlations of laboratory-measured vs. log-measured sonic travel times at in situ conditions
- Evaluation of the use of logging sweeps and logging tools for the determination of tight formation gas potential
- Improved log correlations and analysis of grain density
- Improved log correlations and analysis of cementation factors.

Reservoir Engineering and Pressure Transient Analysis Requirements

- Better pressure transient ways to measure in situ permeability to gas

- Better ways to measure in situ net pay to gas
- Methods for determining gas relative permeability after fracturing treatments from pressure transient and production behavior
- Investigative studies on the effects of permeability vertical distribution profiles on producing rate and ultimate recovery from tight gas formations
- Investigations of the effect of lateral distribution of permeability profiles on production rate behavior and ultimate recovery from tight gas formations
- Computer model sensitivity studies of the performance vs. permeability distributions
- Improved methods for measuring in situ gas porosity distribution
- Improved methods for measuring in situ water saturations
- Improved methods for measuring in situ capillary pressure effects
- Improved methods for measuring in situ vertical permeability distributions
- Improved methods for measuring in situ lateral permeability distributions
- Improved methods for measuring in situ reservoir pressure
- Comprehensive computer model studies of well interference, well spacing, and well location patterns.

Well Completion Requirements

- Investigations of the cementing requirements for massive hydraulic fracturing
- Development of methods to determine cement failure while fracturing with MHF
- Determination of the effects of bad cement jobs on fracture stimulation treatments
- Investigation of the effects of fracture treatment on cement-pipe bond and cement-formation bond.

Hydraulic Fracturing Requirements -- Fracture Propagation Studies

- Improved methods for controlling vertical fracture growth; investigation of the effects of the vertical stress stratification on vertical fracture propagation

- Correlations of compressional and shear wave vs. in situ stresses or rock properties
- Closure stress studies in shales and beds adjacent to the pay formation
- Development of computer models to study fracture propagation and confinement tendencies
- Sensitivity studies of in situ rock properties, bed boundaries, bed thicknesses, in situ stresses on fracture propagation
- The effect of pore pressure on local in situ stress fields
- The effect of both vertical and lateral variations of in situ stresses on fracture extension
- The effect of vertical and lateral rock property variations on fracture extension
- Propagation studies to investigate the tendencies of fractures to propagate from shales into sand lenses, and from lenses into shales
- Improved methods to frac zones which show poor vertical fracture confinement
- The effects of gel dehydration due to leakoff on fracture propagation
- Studies of stress fields existing in sand lenses surrounded by shales
- Studies of fracture growth in limited lenticular structures
- The effect of coal beds on vertical growth.

Hydraulic Fracturing -- Geometry Requirements

- Sensitivity studies comparing effective fracture length vs. hydraulic fracture length
- Development of methods and techniques for measuring hydraulic fracture length
- Development of methods for measuring fracture widths
- Development of methods for measuring fracture height
- Development of methods for measuring or determining fracture shape and configuration
- Determination of the effects of fracture asymmetry on production behavior and on pressure behavior

- Improvement of the methods for determining fracture azimuth
- Studies of the effect of fracture azimuth interference on production type curve analysis
- The effects of proppant banks on fracture shape
- Determination of investigations of rock fabric correlation to fracture geometry.

Hydraulic Fracturing -- Rock Property Testing

- Parametric correlations of mechanical rock properties with physical and lithological properties from lab measurements and well logs
- Methods for determining the mechanical properties of shales
- Correlations of laboratory data with long spaced acoustical survey data
- Development of laboratory methods for performing experiments on the relative fracturability of rocks
- Development of reliable representative laboratory tests to study fracturing tendencies of rocks.

Hydraulic Fracturing -- Fluid Rheology Requirements

- Development of reliable laboratory models to investigate proppant transport
- Development of techniques to characterize non-Newtonian, non-power-law fracturing fluids rheological behavior
- Development of computerized simulators for proppant transport with non-power-law fluids
- Investigation of the proppant transportability of various fluids
- Theoretical and experimental studies of proppant settling in visco-elastic, non-power-law fluids
- The development of technique to predict visco-elastic, non-power-law friction losses in fractures
- Studies of the effect of proppant "clumping" on proppant settling rates
- Development of laboratory equipment and techniques to quantify and characterize the rheological behavior of visco-elastic fluids containing proppant agents at temperatures as high as 400°F.

Hydraulic Fracturing -- Fluid Testing Requirements

- Development of standardized procedures for comparing and characterizing fracturing fluids
- Studies of the effect of fluid loss on the changing viscosity of fluids in a fracture
- Studies of the effects of proppant settling on fluid channeling and causing fluid properties to change in the fracture
- Determination of the necessary rheological tests for characterizing particle transport in fractures
- Studies of comparing dynamic fluid loss vs. static fluid loss tests
- Development of experimental techniques for the quantitative evaluation of dynamic fluid loss in fractures for proppant-laden fluids
- Development of fracturing fluids with high temperature stability, low fluid loss, low viscosity, high friction, and high proppant carrying capabilities.

Hydraulic Fracturing -- Propping Agent and Fracture Conductivity Requirements

- Development of low density, high strength proppants for proppant settling control
- Development of methods for representative measurements of fracture conductivity; the development of techniques to better predict fracture conductivity
- Studies of the effects of fracturing fluid, proppant conductivity interaction
- Studies of the effects of placement techniques for propping agents.

SUGGESTED COMPREHENSIVE RESEARCH PROGRAMS FOR ACCELERATING TECHNOLOGY ADVANCEMENT

The previous section identified a comprehensive list of specific technology items that must be developed or improved to enhance production and recovery from tight gas formations. The list is expansive; any one of these individual items or a small group of them alone cannot be expected to solve the entire tight gas problem. It will be necessary to incorporate and integrate many of these individual areas of technology into the entire advancement effort. In this light, a suggested overall program is presented to address the total needs. It includes procedures and practices to

implement the specific technology listed in the previous section. The program is grouped into four general parts: (1) Evaluation (Page H-8), (2) Resource and Site Characterization (Page H-10), (3) Research, Instrumentation, and Model Development, (Page H-12) and (4) Production Technology Development (Page H-17).

Evaluation

The objectives of the evaluation activity are: (1) to assess the results of the other activities, (2) to continue the development of the data base for tight gas formations, (3) to assess recent technological developments and related industry activities, (4) to update estimates of the potential of the resource, and (5) to develop and monitor plans that reflect the integration of the technical, geologic, economic, and other data. The tasks and elements that support the evaluation activity are listed below.

Acquire and Maintain Existing Geologic and Technological Data Base

These tasks continue throughout tight gas development. Supporting elements vary by the type of data being collected, interpreted, and synthesized.

Assemble Available Data on the Resource. Collect available geologic and reservoir data on tight gas formations in the target basins.

Assemble Data on Industry Activity in the Target Basins. Collect data on industry activity to assist in determining the nature and direction of research and development (R&D) and field development in enhanced gas recovery in the target basins.

Assemble Data on Diagnostic and Stimulation Technology. Collect data on present techniques and the effectiveness of measuring and/or interpreting the rock and reservoir characteristics of target formations. To the extent possible, assess the reliability and accuracy of these instruments for collecting reservoir data in the target formations. Collect data on well completion, stimulation, and field development practices, in addition to well performance and test data, in the target basins. Use these data to update the assessment of the state of the art in recovery technologies.

Identify the Technological Problems That Require Significant Effort

This task continues through the life of the low permeability tight gas development and entails continuing reevaluation of the technological problems that impede the deployment of enhanced gas recovery techniques. Data collected in the data acquisition task ("Acquire and Maintain Existing Geologic and Technological Data Base") (Page H-8) and feedback from ongoing basic and applied R&D provide the basic information necessary to delineate the most significant technological problems.

Update the Comprehensive List of Technological Problems. Refine the comprehensive list of problems that must be solved to make the target basins economically attractive. This list must be specific to particular enhancement techniques and geologic targets. Limitations of present technologies, including diagnostic technology and the actual results of stimulation and production tests, should be defined. The basis should be the continuing analysis of the geologic environments, industry activities, and development problems ("Assemble Data on Industry Activity in the Target Basins" and "Assemble Data on Diagnostic and Stimulation Technology") (Page H-8), and the feedback from basic research and field experiments ("Resource and Site Characterization" (Page H-10), "Research, Instrumentation, and Model Development" (Page H-12), and "Production Technology Development") (Page H-17).

Rank the Technological Problems. Using geologic data, the list of technology problems, and the existing understanding of R&D plans, determine the relative impact of the various technological problems on production economics of several geologic environments. The ones which most affect the production economics should receive the highest ranking. To the extent possible, investment decision criteria and risk asessment methods used in the particular area should be applied.

Develop an R&D Approach as New Problems are Identified. As new problems are identified and ranked, an R&D approach must be developed for solving each. The approach must define the problem, as well as establish R&D activities, the likelihood of success, and successful completion criteria.

Identify Environmental and Other Nontechnical Constraints

Identify environmental constraints that may directly affect drilling operations or generally impede the rate of commercialization in the target basins. In addition, identify the nontechnical constraints that may impede the rate or extent of development. Identify constraints and assess the extent to which they may cause revisions to the evaluation of otherwise attractive targets. Environmental constraints, however, must be addressed directly in programs by environmental analyses (of specific test sites) and pollution control technology development where appropriate.

Identify Environmental Regulations and Cost of Compliance. Define regulations and the cost of compliance for site preparation activities and the disposal of liquid and solid wastes generated by drilling, stimulation, and production. In addition, define those areas within the identified basins where development will not be allowed due to restrictive environmental regulations (other than the Wilderness Act and RARE II regulations).

Determine the Effects of Federal, State, and Local Restrictions on Development. Assess federal, state, and local regulations that will restrict development. Areas that will be affected by the Wilderness Act and RARE II regulations and other governmental regulations (e.g., preservation of archeological sites) should be delineated.

Determine Market Viability and Development Constraints. Determine the availability of local market and pipeline systems, of capital, drilling rigs, well service, manpower, and chemicals and other supplies necessary to commercialize tight gas sands. If limitations exist, determine the effect on the development rate and any implication this may have for the scheduling of R&D efforts.

Update Estimates of Gas In Place, and Technically and Economically Recoverable Gas

This task involves the periodic updating of the estimates of gas in place, technically recoverable gas, and recovery rates for the specific target areas under examination, and of estimating the impact of improved technologies. Initial estimate updates will rely on geologic and technical data developed under the heading "Acquire and Maintain Existing Geologic and Technological Data Base" (Page H-8). Results from the other major activity areas should allow a more precise updating to be performed. In addition, certain nontechnical constraints identified under the heading "Determine Market Viability and Development Constraints" (above) should be assessed for their effect on recovery rates.

Perform Sensitivity Studies. The data from other major activities and tasks and the emergence of new information from outside sources should be used in sensitivity and parametric analyses to help define the critical technology and geologic uncertainties. These should be conducted to identify and refine the definitions of key areas for uncertainty-reduction research, analysis, and methodology development.

Update and Improve Aggregate Potential Model. Based on the sensitivity studies, new data, and the results of the resource characterization and technology R&D conducted within a program, the existing models for estimating overall gas in place, technically recoverable gas, reserve additions, and potential production rate should be updated. Existing models should be adapted to explicitly estimate the level of uncertainty and confidence in these estimates.

Update Estimates of Potential and Uncertainty. The models that result from the update and improvement of the aggregate potential model should be updated to incorporate new information concerning estimates of gas in place, technically recoverable gas, and potential reserve additions and production rates.

Resource and Site Characterization

The primary objective of this activity is to develop the necessary resource data base for specific sites as well as subbasins and basins, so that the information can be used to assess the potential of the resource, to guide modeling efforts, and to design stimulation tests in the various basins and subbasins under study. Using outcrop studies, cores, state-of-the-art diagnostic equipment, and new analytic and interpretive techniques as they become available, various types of resource data should be collected: depth and

composition of pay zones and bounding strata, water and gas saturation, porosity, permeability, nature of gas-bearing lenses (geometry, dominant orientation, distributions), in situ stresses, and other pertinent information. Tasks and elements which support the resource and site characterization activity are listed below.

Perform Basic Geologic Studies

Complementing the acquisition of existing data ("Assemble Available Data on the Resource") (Page H-8) perform basic geologic studies in the priority basins and in as many of the remaining identified basins as possible.

Determine Formation Characteristics. In the basins where basic studies are performed, determine to the extent possible depth and thickness of tight gas (pay) zones, gas and water saturation, porosity and permeability, depositional environment including distribution of blanket sands or sand lenses, major lens orientation, reservoir pressure and temperature, and the distribution of basic rock properties, including dominant regional stress. Conduct basic geochemical and petrophysical studies aimed at gaining a better understanding of gas migration and potential production from tight gas sand formations.

Continue Monitoring Basin Drilling Activities. On a continuing basis, monitor drilling activity in the target basins. To the extent possible, obtain data from the operators; in addition, look areas to "piggy back" the collection of cores and logging data. Synthesize these data for use in the evaluation activity.

Perform Detailed Characterization of Lenticular Sand Basins, Other Types of Tight Basins

To gain a better understanding of gas-bearing formations, their distribution, orientation, and characteristics, perform detailed studies in the priority basins.

Perform Outcrop Studies. Perform outcrop studies in the priority basins to determine lens size, distribution, and dominant orientation of lenticular formations.

Drill and Log Close Spaced Wells Near Outcrops. Drill and log close spaced wells to investigate lens size, distribution, and dominant orientation as an extension of outcrop studies.

Perform Seismic Studies. Assess the feasibility of using seismic techniques to establish the distribution, geometry, and orientation of gas-bearing lenses.

Characterize Other Formation Types. Perform detailed characterization of blanket formations and additional types of tight gas sand formations. Determine the thickness and distribution of pay zones and the characteristics of bounding strata.

Core, Log, and Test Wells of Opportunity

Conduct test work in wells in selected areas of the basins containing low permeability sandstones. Perform coring (including routine analysis), logging, and other tests to measure the characteristics of the formations in the gross interval selected. These tests will include mini-breakdown tests in both sandstones and adjacent strata to determine variations of in situ stress. The information collected should supplement the basic geologic studies.

This task requires the coring, logging, and testing of wells in the priority basins, and the coring, logging, and testing of wells in other tight sand or carbonate basins.

Develop Detailed Geologic Descriptions

Based on data from drilling, outcrop studies, coring, and downhole diagnostic measurements, develop a detailed quantitative description (model) of pay formations and bounding rocks.

Develop Geologic Description of the Target Basins. For major basins, develop detailed geologic descriptions. Stratigraphic correlation maps should be developed which show how depositional environments, stratigraphy, rock composition, and facies change occur over the basin. To the extent possible, water saturation, porosity, in situ permeability, and mechanical properties in both conventional and tight gas sand pay zones and bounding sediments should be correlated over the basin. These descriptions (models) can be used in evaluation; research, instrumentation, and model development; and production technology development.

Develop Site-Specific Geologic Description for Test Design. In the priority basins, develop site-specific geologic descriptions which can be used to estimate pay sand lens(es), geometry, and orientation within a half-mile around the well. The description should include estimates of water saturation, porosity, in situ permeability, stress gradients, and rock composition in the pay zones and bounding sediments.

Research, Instrumentation, and Model Development

The objectives of this activity are to improve or develop new diagnostic techniques, to improve or develop new stimulation approaches, and to improve the ability to acccurately predict and measure reservoir response to stimulation techniques. Fulfilling these objectives requires basic and applied R&D in the laboratory and field and the development of models. The models should serve as the repository of knowledge gained from the R&D. They should describe the present understanding of the stimulation processes, gas flow from the reservoirs, and economic parameters related to fracturing and production. Models and instrumentation should be evaluated and refined based upon the performance of tests under the heading "Production Technology Development" (Page H-17) conducted in the field. Tasks and elements which support the research, instrumentation, and model development activity are listed below.

Develop/Improve Geologic Diagnostic Technology

The elements of this task are directed towards improving existing or developing new tools and techniques for determining geological, chemical, and physical properties of reservoir and bounding rocks. The aim is to obtain a more detailed description of these reservoirs than is presently possible.

Calibrate and Refine Existing Logging Tools and Interpretation Techniques. Calibrate selected available logs used to measure several reservoir parameters with core analyses, drill cutting analyses, and scanning electron microscope studies of rocks and well test results from the same hole to see if correlation can be made between those results and variations in porosity, permeability, and water saturation in tight sand formations. In addition, refine present tools and interpretation techniques so that more accurate and precise evaluations of porosity, permeability, and water saturation are possible.

Develop Improved Logging Tools. Perform basic R&D oriented toward developing entirely new approaches in borehole logging. Tools are needed to provide accurate measurements of porosity, shaliness, formation R_w, permeability, formation factor, and other important parameters to ultimately determine movable hydrocarbon content. Possible techniques include a formation impedance tool, improved sonic techniques, improved NMR, and a downhole hydrocarbon detector. These tools are meant to extend the ability to perform measurements in the region beyond the range of drilling effects.

Develop New Coring Tools and Analytic Procedures. Develop a reliable downhole pressure coring tool and noninvading coring fluids and evaluate them in the field. In addition, perform basic R&D oriented toward developing other approaches to coring. Improved handling and analytical techniques will be required to maintain and determine in situ properties of these cores. Correlations with logs should be made as in the section entitled "Calibrate and Refine Existing Logging Tools and Interpretation Techniques" (Page H-13).

Develop a Standardized Core Analysis Method for Tight Gas Sands. Evaluate current core analysis techniques; assess the adequacy of these approaches for tight gas sands. Develop new techniques which can give higher quality measurements. Select a cost-effective set for routine application.

Improve Various Techniques for Lens Distribution Determination. Refine present surface and downhole seismic techniques for application in determining the distribution and major orientation of sand lenses in a lenticular reservoir. Other techniques should be investigated.

Develop/Improve Stimulation Technology

The elements here are directed toward improving the application of stimulation technology and the ability to measure induced fractures, toward developing tools for precisely measuring downhole parameters critical to fracture design, and toward gaining a better understanding of rock mechanics and other factors which control fracture propagation. This task is synergistically tied to the modeling activities discussed under the heading "Develop Stimulation Models" (Page H-15) and the field activities discussed in "Production Technology Development" (Page H-17).

Improve Frac Fluids. Evaluate existing and develop other frac fluids, if needed, so that maximum propped fracture length is achieved within the reservoir interval and minimal formation damage is caused. This element involves investigating fluid-rock interactions using various fluids and cores. Fluid cleanup should also be investigated. Measure the rheologic properties of frac fluids and evaluate proppant carrying capabilities.

Improve Proppants. Develop improved proppants so that maximum conductivity is attained under reservoir rock pressures. A better understanding of the permeability and embedment of various proppants under closing pressures is needed. Improved high strength, low density, and low cost proppants are required; cost reduction is important.

Develop In Situ Stress Measurement Tools. Develop downhole tools which can measure in situ stress of the target and bounding strata. Ideally, a "wireline" technique should be developed for a rapid, continuous measurement of this important parameter. Various approaches based on mini-fracs, acoustics, borehole deformation, etc., should be investigated.

Improve/Develop Tools for Measuring Physical Dimensions and Shapes of Fractures. Improve or develop new tools which make it possible to measure the azimuth, height, length, width, shape, orientation, and symmetry of induced fractures. Refine the use of tiltmeters, electrical potential equipment, and temperature logs and tracers. Develop new tools to measure the various dimensions of an induced fracture, including the use of seismic and sonic techniques and other unique approaches. This includes the necessary analytical techniques for interpretation.

Improve Rock Mechanics Understanding for Stimulation Techniques. Improve rock mechanics understanding of fracture propagation in geologic materials. Determine the critical relationships between fracture growth and changes in formation properties and in situ stress. Also determine the effects of fluid intrusion on rock properties affecting fracture. Provide measurements of necessary mechanical properties including anisotropy and fracture characteristics. Concurrent laboratory and analytical studies are necessary to achieve this understanding.

Perform Confirmation Tests. Perform various in situ fracturing experiments and then do confirmation tests (e.g., observation wells, mineback, etc.) to observe and analyze the results, thus providing unique insight into fracturing phenomena. Experiments should investigate basic fracturing (formation interfaces, geologic effects, in situ stress, etc.), applied fracturing (proppant transport, fracture conductivity, fluid and rate effects, perforation effects, etc.) and novel fracturing phenomena. These experiments should be integrated with other elements in the stimulation technology and diagnostic technology tasks.

Improve Completion Techniques. Refine/improve cementing and perforation procedures and techniques so that precise control of fluid and proppant along the pipe formation interface is possible during the fracturing process. This element will be assessed in the section entitled "Perform Confirmation Tests" (above) and the field tests in the section entitled "Production Technology Development" (Page H-17).

Investigate New Stimulation Techniques. Perform basic R&D to develop entirely new approaches for stimulating tight task sand formations.

Develop Stimulation Models

Develop or refine 2D and 3D stimulation technology models to predict the length, height, width, conductivity, and azimuth of an induced fracture as a function of lithologic and techtonic parameters and fracture treatment parameters such as fluid properties, proppant properties, and pump rates. This task is synergistically tied to the modeling activities in the section entitled "Develop/Improve Stimulation Technology" (Page H-14) and the field activities in the tasks under the heading of "Production Technology Development" (Page H-17).

Develop Rock Mechanics Model. Develop model(s) which defines the relationship between in situ stress, mechanical properties, changes in pore pressure, layering, geologic features, and other parameters in tight gas sand reservoirs; that is, develop model(s) which will define fracture propagation in inhomogeneous reservoirs.

Develop Fluid Model. Develop model(s) to describe flow and pressure distribution in a propagating fracture. This includes the rheological behavior of different frac fluids.

Develop Proppant Transport Model. Develop model(s) which realistically defines proppant transport with respect to fluid rheology, injection rates, fracture aperture, and proppant characteristics. This also includes determination of proppant distribution and resultant conductivity.

Synthesize Predictive Stimulation Model. Use information from the sections entitled "Develop New Production Testing Techniques" (Page H-16), "Develop or Improve Data Analysis Techniques for Production Testing" (Page H-16), and "Develop Reservoir Flow and/or

Pressure Model(s) for Tight Gas Reservoirs" (Page H-16) to synthesize a predictive stimulation model(s) which can be used to predict the dimensions, geometry, azimuth, and efficiency of a propped fracture induced in various geologic environments.

Develop Production Testing Capability and Reservoir Model(s)

Elements of this task are directed at improving producing testing tools and data analysis techniques so that accurate estimates of production from tight gas sand formations can be made quickly. This information should be used in developing gas flow models which will take into account both the geometry of an induced fracture and the efficiency of the propped fracture in order to simulate reservoir gas flow and pressure.

Develop New Production Testing Techniques. Develop new production testing tasks such as temperature tools, multizone testing tools, and tubing shutoff tools.

Develop or Improve Data Analysis Techniques for Production Testing. Apply existing data analysis techniques to the improved test data with respect to inhomogeneous reservoirs. Develop new techniques such as early time analysis. Select improved analyses for routine use.

Develop Reservoir Flow and/or Pressure Model(s) for Tight Gas Reservoirs. Evaluate existing reservoir models for application to the reservoir of interest. Select and/or develop models for simulating gas flow and pressure behavior. Determine the need for three-dimensional models (of increased complexity and cost) as compared with modified two-dimensional approaches. Optimum models will be developed for lenticular, blanket, and other reservoirs as appropriate. These models will be verified and then simplified for easier application.

Develop Systems Model

The elements of this task are directed at the development of an overall systems model which utilizes all development costs in the target basins, risk assessment methods in combination with the models developed in the sections entitled "Develop Stimulation Models" (Page H-15) and "Develop Production Testing Capability and Reservoir Model(s)" (Page H-16), to predict production and economic results.

Develop Detailed Cost Estimates. Develop detailed cost estimates for all aspects of field development of tight formations. Fracturing costs will be based on specific types of technologies and reservoirs, and regional supplies and servicing costs.

Develop Risk Assessment Method. Define and categorize the uncertainties of risks involved in developing a specific site. Develop methods for quantifying the extent of risks posed by geologic uncertainty, diagnostic reliability, stimulation reliability, and uncertain costs.

Integrate Fracturing Costs, Risk Assessment, and Other Models. Integrate the outputs from "Develop Detailed Cost Estimates" (above) and "Develop Risk Assessment Method" (above) with the reservoir and stimulation models to result in an overall systems model.

Predict Production Results in Various Geologic Environments. Using the systems model, develop production estimates for various types of tight gas sand reservoirs in the target basins. The systems model should be applied for specific test-site evaluations (in the section below entitled "Production Technology Development").

Production Technology Development

The prime objective here is to develop the ability to design and apply massive hydraulic fractures so that the induced fracture drains the largest possible area of a particular reservoir and the resultant geometry (height, length, width, and azimuth) of the fracture conforms to the designed geometry and model predictions. Two types of field tests will help to achieve this objective: (1) highly instrumented and heavily tested research wells using developing technologies to advance the state of the art; and (2) confirmation wells to test the ability to understand the resource, conduct an appropriate stimulation, and economically produce the gas. Tasks and elements which support the production technology activity are listed below.

Perform Single and Multiwell Experiments

Elements of this task are the series of activities that are necessary to drill, core, log, test, and evaluate a number of wells in representative areas of the priority basins. The elements support both a comprehensive characterization and the application and evaluation of state-of-the-art and developing technology to tight gas formations.

Develop Detailed Technical Plans. Develop a comprehensive plan and schedule for all task elements including budgeting and reporting responsibilities. Address environmental problems.

Execute Drilling Program. Execute a carefully planned drilling program which satisfies the data collection requirements of the single well and multiwell experiments. Planning details include bit selection, mud program, coring and logging programs, testing, casing, and cementing programs, in addition to site activities such as mobilization, demobilization, road construction, and maintenance.

Perform Laboratory Testing. Perform extensive core analyses including mechanical properties, geochemical analyses, physical properties, and formation characteristics. Perform laboratory tests and analyses on samples of formation fluids obtained during production testing and on samples of frac fluids and proppants collected during stimulation. Study fracture fluid-formation interactions and the effects of breakage and embedment on proppants.

Perform Stimulations. Using the models developed in the section entitled "Research, Instrumentation, and Model Development" (Page H-12) as well as data from coring, logging, and lab analyses, predict the performance of alternative fracture design. Then perform carefully planned fractures in several zones using different concepts and variation in treatment parameters. The fracture program should include fracture geometry measurements as well as the efforts to evaluate proppants and fluids.

Perform Production Testing. Perform a well testing program, including as many individual intervals and zones as possible both before and after stimulations. These tests must include drill stem tests, pressure drawdown and buildup tests, and when possible, interference or pulse testing between adjacent wells. Finally, long-term production tests should be performed.

Collect Detailed Field Diagnostic Measurements. Several techniques should be used to collect diagnostic data on lenticular sands, including high resolution seismic reflection and surface-to-well and well-to-well geophone techniques. In situ stress variation within selected strata can be measured by performing mini-fracs over short intervals. Fracture orientations may possibly be obtained by impression packers or downhole seismic tools. Induced fracture orientation can possibly be measured at the surface using the tiltmeter and electric potential equipment while fracture orientation and height downhole may be measured with such technqiues as borehole seismic, hydrophones, and temperature logs.

Perform Analysis and Evaluation. Use geologic reservoir and fracture models and the data obtained from the tests to evaluate stimulation tests. Using the results of the field tests, compare model predictions with actual field results. Determine if in situ conditions were not diagnosed accurately before fracturing or if fractures fail to attain their designed effective lengths.

Perform Field Confirmation Tests

The objective is to verify that the state-of-the-art diagnostic, stimulation, and production technology can be economically applied in the field development (as opposed to research) context. In short, the elements below will be "development procedures" rather than experiments by the time confirmation tests are performed.

Develop Detailed Technical Plans. Develop a comprehensive detailed plan and schedule for all task elements.

Execute Drilling Program. Execute a drilling program which optimizes the results of completed multiwell and single well experiments.

Perform Laboratory Testing. Limited core analyses and some laboratory tests and analyses may be utilized for stimulation design.

Perform Stimulations. Perform carefully planned fractures in several zones using concepts and treatment parameters developed in the multiwell tests. The fracturing program must include fracture geometry measurements.

Perform Production Testing. Utilizing selected well testing procedures, perform a well test program which includes pre- and post-stimulation tests.

Collect Field Diagnostic Measurements. Perform selected field diagnostic measurements as required.

Perform Analysis and Evaluation. Verify that the state-of-the-art diagnostic, stimulation, and production technology can be economically applied in a field development.

Specify Stimulation Design Procedures for Technology Transfer

Elements of this task support the development of reservoir evaluation and stimulation design manuals which can be used to develop tight gas sand resources.

Assemble Data and Develop Fracturing Manuals. As experiments are completed for various types of tight gas sand reservoirs, assemble the data and develop fracturing manuals.

Update Manuals. As additional data become available from R&D efforts, update the fracturing manuals for various geologic environments.

APPENDIX I

Glossary

GLOSSARY

advanced technology -- assumes improvement through research and development with wells having fracture lengths of 2,000 to 4,000 feet and 1,000 md-ft conductivity, with no more than 12 wells per section.

AF_{depth} factor -- a numerical factor to adjust a basic fracturing cost for higher costs in deeper wells.

$AF_{location}$ factor -- a numerical factor to adjust a basic fracturing cost for higher costs in certain locations.

areal average -- average value of reservoir properties taking into account the individual values of the various parts of the area.

azimuthal direction -- the orientation of a fracture expressed as a compass orientation.

base technology -- currently available technology assuming production from wells with fracture lengths of 1,000 feet (from well bore to tip) and conductivity of 500 md-ft, with no more than four wells per section.

basin -- a general term for a depressed, sediment-filled area which may range from circular to elliptical.

bedding feature -- a feature within a sedimentary unit (bed) which may be of a distinct color, mineral makeup, fossil assemblage, and/or hardness.

behind the pipe gas -- gas that exists in low permeability reservoirs behind existing casing in conventional oil and gas fields.

biogenic gas -- natural gas formed by reduction of hydrocarbons by bacterial action.

blanket sand -- a sand stratum within a formation, or a formation which is continuous over a wide area.

borehole gravimeter survey -- a well log showing changes in gravity over the length of a well. Interpretation is in terms of density changes in the fluid and rock volume (bulk density) adjacent to the the well bore.

Btu -- British thermal unit; a unit of energy approximately equal to the energy needed to raise the temperature of one pound of water by one degree Fahrenheit.

Btu/MMCF -- heat energy obtainable by burning one million cubic feet of gas.

cash flow -- net profit after taxes plus charges to depreciation, amortization, and like accounts.

cash flow stream -- annual values of net profit or loss after taxes. Annual cash flow.

cash outlay -- total cash expenditures.

committed wells -- in a scenario, the number of wells for which funds are committed in any one year. This number consists of the wildcats drilled in that year plus development wells to be drilled in the future.

conductivity -- a measure of the ability of the hydraulic fracture to transmit gas.

constant 1979 dollars -- dollars with the purchasing power of the U.S. dollar in the year 1979. This term is used to provide a measure of comparability to project costs, revenues, rates of return, and capital requirements which might otherwise be distorted by varying estimates of the unpredictable factor of inflation or deflation in future years.

conventional gas -- gas produced by customary technology from reservoirs having permeability greater than 1 millidarcy; the usual, or "conventional," gas production.

DCF ROR -- discounted cash flow rate of return.

decline rate -- percentage or fraction by which well production declines with time.

density -- weight or mass per unit volume, such as pounds per cubic foot.

development wells -- wells drilled to increase production in established fields.

discounted cash flow rate of return (DCF ROR) -- that discount rate which will balance cash expenditures against revenues in the annual cash flow stream such that net present value is zero.

discounted present worth -- value of an asset expressed as the sum of all payments generated by the asset, discounted to their present value.

dry hole -- a well that either finds no oil or gas, or finds too little to make it financially profitable.

E and P simulator -- a computer model of the exploration and production segment of the petroleum industry.

EIA -- Energy Information Administration of the U.S. Department of Energy.

exploration play -- drilling for oil or gas by one or more operators in a basin thought to contain hydrocarbons.

field -- an area from which petroleum has been produced.

field size distribution -- a probability distribution of the natural geographic range of field sizes.

formation -- a persistent body of rock having easily recognizable upper and lower boundaries; under the proper conditions, it may be a reservoir.

frac fluid -- the thickened fluid used to open the fracture and to transplant the proppant into the fracture during fracturing operations.

fracture -- a crack in reservoir rock, especially as distinguished from a pore space.

fracturing -- artificial hydraulic fracturing.

fracturing fluid rheology -- characteristics of fracturing fluids that determine their ability to create hydraulic fractures and transport fracture proppants along with attendant properties.

gas in place -- all of the gas a reservoir contains; exceeds the amount of gas which can or will be produced.

GIP -- gas in place.

hydraulic length -- the fracture length measured from the well bore to the tip of the fracture as created during hydrualic fracture pumping operations.

infill drilling -- drilling additional wells in an established pattern.

initial production rate -- the amount of gas produced in the first year of a well's life.

in situ -- in the reservoir.

in situ gas porosity -- porosity in the reservoir under predominant conditions; i.e., overburden pressure, pore pressure, temperature, and water saturation.

k -- symbol for permeability.

lens -- a sedimentary deposit of irregular shape surrounded by impervious rock.

lenticular sand -- discrete, discontinous, lens-shaped sand bodies within a formation.

Lewin Report -- report on enhanced recovery prepared by Lewin and Associates and issued by the Federal Energy Administration in April 1976.

linear flow -- the direct flow of gas into the fracture and to the well bore via the fracture (as contrasted to radial flow in an unfractured reservoir to the well bore through the reservoir rock matrix).

M -- thousand.

marginal rate of return -- a specified rate of return (in this study, 10, 15, and 20 percent) which must be equalled or exceeded by each basin or subbasin before being accepted as an economical project.

massive hydraulic fracturing (MHF) -- hydraulic fracturing using large volumes of solid-laden fluids, usually into a low permeability, gas-bearing formation to create a highly conductive drainage channel to drain gas into the well bore.

maximum recoverable gas -- the amount of gas that can be theoretically recovered irrespective of time or economic constraints.

md -- millidarcy.

millidarcy -- a unit of permeability.

millidarcy-feet (md-ft) -- a measure of the conductivity of a fracture defined by the product of proppant permeability and fracture width.

minimum DCF ROR requirements -- DCF ROR, minimum requirement of 10 percent.

MM -- million.

Monte Carlo technique -- the use of random numbers to sample a range of values used here to provide input data for a computer model.

μ (mu) -- symbol for viscosity.

natural gas -- in situ hydrocarbons and other chemicals produced as a gas, usually predominantly methane.

natural gas liquids (NGL) -- liquid petroleum produced in the natural gas stream, usually expressed as barrels per million cubic feet of gas.

net pay -- the vertical measurement in feet of gas-bearing porosity in a reservoir.

net present value (NPV) -- present value of anticipated future returns, discounted at the required rate of return, less the present value of the cost of the investment.

NGPA -- Natural Gas Policy Act of November 9, 1978.

nominal rate of return -- rate of return from an investment in current dollars instead of constant dollars.

normal -- perpendicular to (intersecting at a 90° angle).

nuclear magnetic resonance log -- a well log in which relaxation times of hydrogen nuclei are measured in response to an imposed magnetic field; may be interpreted to show bound water and water free to flow in formation pores.

outcrop -- that part of a geologic formation or structure that appears at the surface of the earth.

payout time -- the length of time required for cash inflows to equal original cash outlays, or the length of time from project initiation to the time cumulative cash flow becomes positive.

permeability -- an index of the ability of reservoir rock to transmit fluids under the influence of a pressure gradient.

pore space -- a small natural hole in reservoir rock which contains fluid or fluids.

porosity -- ratio of pore volume and fracture volume to total volume in reservoir rock, usually expressed as a percentage.

Potential Gas Committee -- an independent committee established to provide realistic estimates of U.S. gas resources. Membership is composed of working members from all segments of the Natural Gas Industry including producing pipeline and distributing companies, as well as experts from federal and state government agencies, private consultants, and academic institutions. Observers to the Committee are appointed from pertinent federal agencies, interstate organizations, and industry associations. The Committee functions independently but with the guidance and assistance of the Potential Gas Agency of the Colorado School of Mines. The Potential Gas Agency is supported by the American Gas Association.

productive area -- the portion of a basin or subbasin with underlying formations containing natural gas.

profit per investment -- undiscounted net cash recovery divided by undiscounted investment expressed as dollar profit per dollar invested.

proppant -- the solid material, usually sand, injected during hydraulic fracturing to prevent the fracture from closing on termination of pumping.

propped length -- hydraulic fracture length measured from the well bore to the end of the fracture held open by proppant.

prospect -- a wildcat location which, if productive, leads to the development of a field.

R&D -- research and development.

recompletion -- production from a newly opened, low permeability gas reservoir penetrated by an existing well in a depleted conventional gas or oil field.

recovery factor -- a multiplier for permeability designed to account for reductions from assumed averages of permeability and porosity.

reserves -- recoverable oil or gas; unless qualified, means economically recoverable oil or gas with proven technology.

reservoir -- a part of the earth rock below the surface, normally sedimentary, that contains petroleum or natural gas which has been or can be subjected to oil or gas recovery.

reservoir performance -- behavior of a reservoir undergoing oil or gas recovery.

resistivity log -- any one of several electrical logs which measure formation electrical resistivity or its reciprocal, conductivity. Interpretation is in terms of net feet of pay in a reservoir.

resource base -- total petroleum in situ which may be subjected to attempted oil recovery.

rock matrix pore throat -- the interconnection between pore spaces which is usually smaller than the pore space and can be the limiting factor in reservoir fluid (gas) flow.

scenario -- a schedule for drilling prospects in one or more basins or subbasins.

section -- for the purposes of this study, a gas-producing area equivalent to one square mile.

stacked formations -- two or more producing formations penetrated by a single well.

state of nature -- if no gas is present in the target formation, state of nature is "dry." If gas is present, state of nature is productive, but not necesarily financially profitable.

state-of-the-art -- the overall stage of development of a process and its background R&D.

stylolites -- a thin seam or contact usually occurring in homogeneous carbonate rocks and rarely in sandstones and quartzites; as usually seen in cross-section, resembles a suture or the tracing of a stylus. Commonly parallel to the bedding.

sweet spot -- local areas within a formation in which abnormal porosities, permeabilities, and/or natural fracturing exist which, in turn, enhance production characteristics.

thermal carbonization -- distruction of natural gas by excessive formation temperature.

tight gas sands -- reservoir rock containing natural gas that cannot be recovered under current economic and technologic conditions because of low permeability.

trap -- a reservoir or portion of a reservoir in which gas is contained by means of structural and/or stratigraphic changes.

ultimate recoverable gas -- that gas which can be recovered at a profit; generally, a major portion of the gas in place.

velocity log (sonic log) -- a log of acoustic velocity in the strata penetrated by a well. Interpretation is in terms of porosity and gas-filled pores.

well -- a hole drilled into the earth for the purpose of removing fluid from a reservoir or putting fluid into a reservoir.

well bore -- the hole in the earth comprising a well; a well.

well density factor (WDF) -- a multiplier for recoverable gas to account for drilling fewer than the number of wells required for total recovery.

wildcat -- an exploration well drilled in an area where there has been no previous tight gas production.

wildcat success ratio -- the number of productive wildcats in a play divided by the total number of wildcats in the play.

working interest -- the fraction of production retained by the operator after royalty payment to the leaseholder.