EXECUTIVE SUMMARY

UNCONVENTIONAL GAS SOURCES

NATIONAL PETROLEUM COUNCIL • DEC. 1980

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

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PREFACE

There is increasing recognition among all sectors of the nation's economy that oil and gas must continue to supply the United States with the majority of its energy requirements over the near term. The long lead time required for conversion from oil or gas to coal and for development of a synthetic fuel industry dictates this. In the interim period, the nation must seek a resource that can be developed quickly, incrementally, and with as few environmental concerns as possible. One option which could potentially fit these requirements is to explore for, drill, and produce "unconventional gas": Devonian Shale gas, coal seam gas, gas dissolved in geopressured brines, and gas from tight reservoirs. This report addresses the significance of these sources and the economic and technical conditions under which they could be developed.

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 coal seams, Devonian Shale, 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 the 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 Co-chairman of the Committee. A Coordinating Subcommittee and four task groups, by source, were formed to assist the Committee. (Rosters of these study groups are included in Appendix B.) An attempt was made in forming these study groups to include participants with divergent views. This sometimes led to different projections into the future. When such differences arose, the study groups relied on available factual data rather than on theory. This report represents a consensus view of the results of the study. Discussions are given, however, of items for which differences in viewpoint arose and of the manner in which the consensus view was obtained.

Several previous studies of these resources have been made by various groups. The 1973 National Gas Survey, sponsored by the

Federal Power Commission, estimated gas resources in place in some western tight gas basins and in the Devonian Shale. No estimates were made of recovery or economics. The Office of Technology Assessment (OTA) studied Devonian Shale gas and estimated potentially recoverable reserves and future production rates for several gas prices; their report was issued in 1977. The most recent study was that of Lewin and Associates in 1979 which estimated potential reserves and future production rates for each of the four types of unconventional gas sources covered by this NPC study. In this report, NPC estimates are compared with estimates from the OTA and Lewin studies. There is general agreement among these reports as to the potential of the sources.

The National Petroleum Council's report, 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. This Executive Summary provides an overview of Volumes II, III, IV, and V.

RESULTS

Within each volume, the resource base, state-of-the-art of recovery technology, potential reserves and production, constraints, and uncertainties associated with each source are examined. 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.

Resource

In this report, the in-place gas resource of coal seams, Devonian Shale, and tight gas reservoirs is estimated to be very large. No independent estimate of the in-place gas of geopressured brines is made since published estimates are so large that total resource size is not considered a constraint to development. Even though only a portion of these sources' in-place resource is estimated to be economically recoverable, unconventional gas could be a significant addition to the nation's future gas supply.

The resource estimates depend heavily on the extrapolation of limited data. The coal seams estimate is based on available limited gas content data which pertain mostly to known gassy bituminous coals. The Devonian Shale estimate is also based on rather limited measurements on black and gray Devonian Shale. Although there is already significant shale gas production in some portions of the Appalachian basin, most of the resource is in undrilled and unproved areas. The resource estimates for tight gas reservoirs are based on detailed evaluations of 12 basins out of the 113 U.S. basins (excluding Alaska) that produce gas. Results for these 12 basins were extrapolated to the other basins.

Reserve Additions

For each source, reserve additions and production rates are calculated as functions of five gas prices ($2.50, $3.50, $5.00, $7.00, and $9.00 per million Btu [MMBtu]), three rates of return (10, 15, and 20 percent),[1] and at least two levels of technology. Constant January 1, 1979, dollars are used in all analyses. Potential additions shown on Table 1 are cumulative additions through the year 2000, and the prices give a 10, 15, or 20 percent discounted cash flow rate of return (ROR) to the producer on the highest cost (last) increment of production. These reserve additions (and the production rates shown in Table 2) reflect conventional technology for coal seams, Devonian Shale, and geopressured brines. They reflect a development schedule called a "standard scenario" for tight gas reservoirs which assumes a phasing-in of advanced technology. The potential tight gas reserve additions by the year 2000 represent about half the resource expected to be ultimately recoverable (see Table 4 of the Tight Gas Reservoirs section of this volume).

Gas prices of $5.00 and $9.00/MMBtu are equivalent to $29.00 and $52.00 per barrel of crude oil and bracket present decontrolled crude oil prices. Unconventional gas production from coal seams, Devonian Shale, and geopressured brines qualifies for decontrolled high-cost gas prices. Production from tight gas reservoirs qualifies for a controlled incentive gas price of $4.59/MMBtu as of September 22, 1980 ($3.33/MMBtu in January 1, 1979, dollars). The incentive price encourages tight gas development, and when gas prices are deregulated in 1985-1987, the rate of reserve additions should increase.

The estimates in Table 1 may be optimistic because, when faced with a choice on a critical parameter, the study participants usually made the optimistic choice.

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[1]These rates of return are real rates of return on investment, after tax, and take risk into account. They do not reflect inflation.

TABLE 1

Cumulative Potential Reserve Additions to the Year 2000
(TCF)

Source	Gas Price (Constant 1979 Dollars)								
	$2.50/MMBtu			$5.00/MMBtu			$9.00/MMBtu		
	10% ROR	15% ROR	20% ROR	10% ROR	15% ROR	20% ROR	10% ROR	15% ROR	20% ROR
Coal Seams	5	3	2	25	20	17	45	38	33
Devonian Shale	7	3	0.3	20	15	11	27	23	21
Geopressured Brines	0	0	0	0.1	0.1	0.1	0.6	0.5	0.3
Tight Gas Reservoirs	--	156	--	237	229	223	--	290	--

Production Rates

Potential production rates for unconventional gas in 1990 and the year 2000 are given in Table 2. These rates assume a high rate of exploration and development. Tight gas reservoirs offer the largest contribution to potential production rates. The rate of development which could lead to the tight gas production rates shown in Table 2 (and to the reserve additions shown in Table 1) is called the standard scenario. It is believed that this scenario is achievable but only with a high degree of effort and commitment.

TABLE 2

Potential Production Rates, 10% Rate of Return, For Gas Price of Up to $9.00/MMBtu (TCF/Yr)

Source	1990	2000
Coal Seams	0.6	2.4
Devonian Shale	0.6	1.0
Geopressured Brines	0.05	0.08
Tight Gas Reservoirs	2.5	10.5
	3.8	14.0

CONCLUSIONS

The potential for recovery from unconventional gas sources involves complex relationships among resource base, technology, economics, and government policy, making generalizations difficult. From its study, however, the National Petroleum Council draws the following interrelated conclusions:

- Natural gas from coal seams, Devonian Shale, and tight gas reservoirs could make a significant contribution to future U.S. gas supply. Conventional natural gas reserve additions have been 10-14 TCF annually in recent years. At the $5.00 per MMBtu gas price level and a 10 percent real ROR after tax, the total unconventional reserve additions through 2000, if achieved between 1981 and 2000, would average about 14 TCF per year. Because of the difficulty of properly assessing risk, anticipated rates of return higher than 10 percent may be required to attract investment, at least initially. By the year 2000, annual production could be about 10 TCF from tight gas reservoirs, 2 TCF from coal seams, and 1 TCF from Devonian Shale, with negligible production from geopressured brines.

- There is considerable uncertainty in the estimates of reserve additions and production rates. An indication of this uncertainty is shown by the range of estimates in Table 1. The geologic and technical uncertainties for most sources are so great that resource base assessments as well as reserve addition and production rate estimates for any specified economic condition may be substantially in error. Further resource characterization studies, research and development, and field experience will be required to improve prediction capabilities.

- The rate of development of unconventional sources will be highly dependent on economic conditions. These sources contain high-cost gas which generally was not produced at prior gas prices. As mentioned previously, these sources now qualify for decontrolled or incentive gas prices; however, current levels of gas supplies are suppressing field prices in certain areas. Estimates in this report assume that markets will exist for the producible gas. Thus, government actions affecting gas usage could significantly impact the rate of unconventional gas development. The resolution of legal questions as to the ownership of coal seams and geopressured brines gas will also impact their development.

  Significant risk and capital requirements are also associated with the development of these resources. Achievement of the reserve additions estimated for coal seams, Devonian Shale, and tight gas reservoirs will involve capital needs in excess of $200 billion. Such projects will have to compete for available funds with other energy activities, including conventional oil and gas exploration and production as well as other emerging technologies (synfuels, shale oil, etc.). Gas will also have to compete with other fuels for its share of the market.

ECONOMIC EVALUATION

This section contains a listing and discussion of the parameters used in economic evaluations in this study. Each of the source volumes also has a section on economics providing additional details of the economic calculation methods pertaining to each gas source. A listing of the economic parameters follows:

- Basis

  - January 1, 1979, dollars held constant.

- Gas Price

  - Price at point of sale. All capital to that point, such as compression and gathering lines, was included in the evaluation.

  - For coal seam gas which is to enter a pipeline system, the gas must be gathered and the CO_2 removed; the gas is then transported further to the point of sale to a pipeline. Coal seam gas might also be sold for local use prior to cleanup and compression. For completeness, prices both with and without cleanup and compression costs are presented. We assumed that small amounts of oxygen and nitrogen in coal seam gas can be taken into account by reducing the gas price in proportion to their percentage in total gas. For Devonian Shale gas, the gas price was adjusted upward similarly to account for higher than 1,000 Btu per cubic foot of heating value. Devonian Shale gas is now customarily sold prior to compression. For completeness, the add-on cost of compression and transport to a pipeline was calculated and presented for a range of gas prices.

  - The lowest gas price considered is that which gives a 10 percent rate of return, after tax for the best prospect, taking risk into account. The upper limit is $9.00/MCF for 1,000 Btu per cubic foot of gas. For final calculations, gas prices of $2.50, $3.50, $5.00, $7.00, and $9.00/MMBtu were used.

- Cases

Two cases were considered:

  - Current technology -- as likely to evolve and improve during normal operations; this is the base case.

  - Improved technology -- effect and timing were 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 -- chosen as typical for each area; generally in the range of 1/8 to 1/6.

- Taxes - 46 percent federal income tax rate
  2 percent state income tax rate
  10 percent federal investment tax credit on tangible equipment
  10 percent additional energy property tax credit on tangible equipment used to produce gas from geopressured brines and placed in service in the period September 30, 1978, to January 1, 1983.[2]

- Depletion Allowance -- Statutory rates to be compared with 50 percent of net income and cost depletion in customary computation, as follows:

  Statutory depletion allowance of 10 percent on value of gas produced from geopressured brine wells drilled in the period September 30, 1978, to January 1, 1984.[2]

  Statutory depletion allowance on value of hot water produced if used for geothermal purposes, as follows:

1979, 1980	- 22%
1981	- 20%
1982	- 18%
1983	- 16%
1984 and thereafter	- 15%

- Overhead -- 10 percent of invested capital
  20 percent of direct operating cost

- Treatment of costs for tax purposes

  - Expense intangible drilling and development costs.

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

  - Treat leasehold and exploration costs in the most favorable manner permitted by current tax laws and regulations.

- Treatment of dry hole costs and other risks. Burden successful wells with their share of dry hole costs (unsuccessful exploration, leasehold, and other nonrecoverable costs).

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[2]This credit and depletion allowance were assumed to continue to the year 2000 since it had little effect on results.

- Rates of return
  - Base case 10 percent, after tax.
  - Also, additional cases were computed for 15 and 20 percent rates of return.
- Inflation rate (for purposes of computing taxes) was 8 percent.

COAL SEAMS

RESOURCE

Description

Coal-bed gas is a natural byproduct of coal formation and can be found in varying quantities in coal seams lying below drainage. Although a large portion of the gas thus formed has escaped to the atmosphere, a portion has been trapped and remains in place. Coal-bed gas molecules exhibit a high affinity for their parent material which enables larger volumes of the gas to be stored in coal than in porous media (sandstones, etc.) at the same conditions. Methane is the primary component and generally comprises 85 to 99 percent of the volume. Its calorific value varies from 850 to 1,050 Btu per cubic foot; a value of 1,000 was assumed for this study.

Coal-bed gas contains only a slight portion (less than 2 percent) of the total energy contained by the coal that hosts it.

Magnitude

The coal gas resource is intimately related to the coal resource base itself. Only limited coal seam gas content data are available and they pertain mostly to known, gassy bituminous coals.

Table 3 presents coal gas resources which have been projected from published U.S. Geological Survey (USGS) resource data and from study participant deliberations on the gas content of coals.

TABLE 3

Estimated In-Place Resource of Coal-Bed Gas

Coal Category	Estimated Coal Resource (Billions of Short Tons)	Estimated Gas Content (Ft^3/Ton)	Projected Gas Resource (TCF)
1. 300-3,000 feet deep (identified and hypothetical)			
A. Anthracite	46	200	9
B. Bituminous	1,001	200	200
C. Subbituminous	1,137	80	91
D. Lignite	504	40	20
2. 3,000-6,000 feet deep (hypothetical)	388	200	78
Total			398

EXPLORATION REQUIRED TO LOCATE THE BETTER RESOURCE

A considerable amount of information pertaining to the gas-producing potential of coal seams exists and has already been evaluated during the course of oil and gas drilling activity.

METHODS OF RECOVERY

The major techniques for recovering coal-bed gas are:

- Hydraulically stimulated vertical wells
- Unstimulated horizontal holes from vertical shafts
- Unstimulated horizontal holes from mine access
- Slant holes that terminate with long horizontal in-seam segments.

In order to meet near-term, economically sensible energy needs, the viable alternatives have been reduced to either hydraulically stimulated vertical wells or to unstimulated horizontal wells from vertical shafts. Many experienced coal mine operators have expressed concern over the possibility that hydraulically induced fractures can impose additional risk to safe and efficient mining operations. Some of the few hydraulic fractures that have been mined through and visually inspected tend to support the contentions of the unpredictable nature of hydraulically induced fractures.

The measured gas production from horizontal holes is substantially greater than that of hydraulically stimulated vertical wells completed in the same seam. Gas productions of up to 30 thousand cubic feet per day (MCF/D) per 100 feet of horizontal hole length and hole lengths in excess of 1,000 feet have been reported. The U.S. Bureau of Mines has already demonstrated the technical feasibility of unstimulated horizontal holes drilled from a shaft into the gassy Pittsburgh coal seam in northern West Virginia.

STUDY METHODOLOGY

In order to relate gas production on a uniformly applicable basis, it was decided to project likely gas production per foot of coal seam thickness. This approach lends itself to an economic evaluation dictated by the total thickness of coal-bearing strata at any given location.

The average coal thickness for each coal-bearing county was calculated from published USGS total in-place coal tonnage, published areal extent of the county, and the coal density upon which the USGS data were based.

Thirty percent of the in-place reserves lying at depths of 1,000 feet or less were eliminated based on the assumption that shallow coals would contain little, if any, producible coal-bed gas. The total resource for each coal rank as a function of seam thickness was plotted on a graph. Hypothetical scenarios for multiwell projects, including water handling, small wellhead compressors, piping, etc., were employed for cost-estimating purposes. An annual rate of production decline of 10 percent and a 90 percent drilling success ratio were employed. A production life of 12 years and an overall project life of 20 years were used in the economic evaluations.

Gas production at six different rates, ranging from 10 to 150 MCF/D per well, were used. Costs for add-on items, such as scrubbing, high-pressure compression, etc., were calculated and presented separately for each case ($0.60-$2.00 per MCF). A discounted cash flow analysis based on the different gas production scenarios was generated using the financial guidelines established for the study.

RESULTS

The cumulative additions to ultimate recovery to the year 2000 that are likely to evolve during the next 20 years were projected for both stimulated vertical wells and horizontal holes from vertical shafts. It should be pointed out that the productions from these two scenarios are mutually exclusive. The results are difficult to present concisely in tabular form and are thus presented in graph form in Figures 1 and 2.

CONSTRAINTS

Legal

The coal-bed gas ownership issue is unresolved and will have to await final court decision. A need exists to review state and other local regulations that may also be of importance.

Environmental

The most significant environmental constraint relates to the disposal of produced water. The composition of coal-bed water varies from slightly acidic to slightly alkaline and only minimal knowledge of the mineral makeup is available. Where water availability is an issue (as in some western locales), the water table drawdown becomes an issue in itself.

Commercial

Uncertainties in the rate and decline of coal-bed gas are likely to deter the finalization of gas purchase agreements. Impurities such as water and carbon dioxide are also of concern because of their corrosive potential when combined. Gas produced

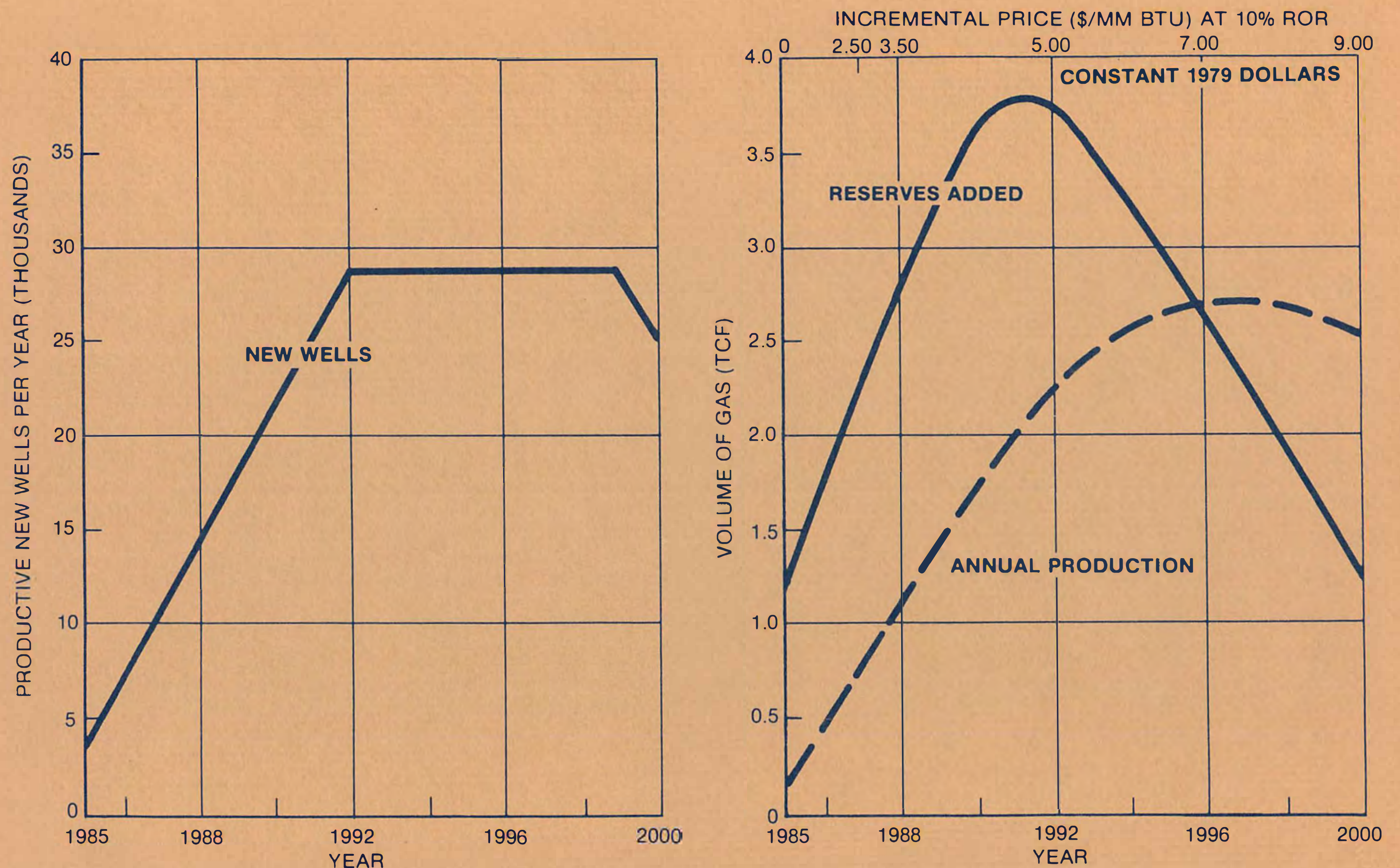


Figure 1. Annual Rates as a Function of Time--
Vertical Wells Projects (Raw Gas on Site).

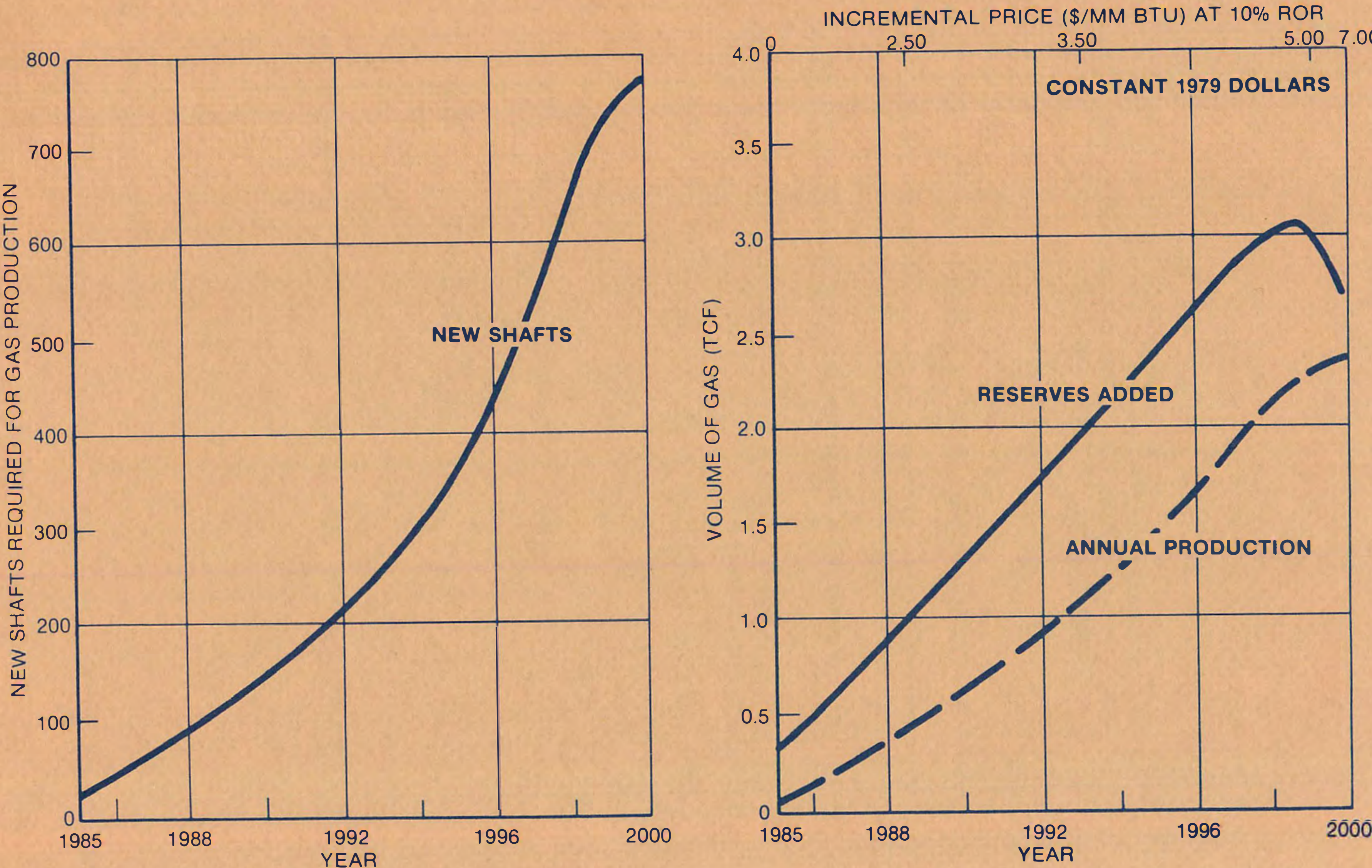


Figure 2. Annual Rates as a Function of Time--
Shafts with Horizontal Holes (Raw Gas on Site).

from projects coupled with active mining must be free to flow unencumbered to prevent gas "backup" into the mines.

Technological

A need exists to obtain additional baseline information on the gas-producing characteristics of coal reservoirs. Gas production rates cannot be predicted for extended periods with any degree of certainty. Adequate equipment (production, handling, etc.) appears to be commercially available. A new generation of directional surveying and drill guidance hardware is evolving. The further development of these items is essential to the success of routine in-seam long horizontal hole drilling operations.

MAJOR UNCERTAINTIES

The major uncertainties in coal seam gas development are:

- Long-term gas and water producing characteristics from coal seams (rates, declines, compositional changes)
- Environmental constraints pertaining to the effect of and to the disposal of ground water
- Coal seams being rendered economically unmineable by hydraulically created fractures
- Gas content of nonbituminous coal
- Gas-producing potential of most coal seams
- Coal-bed gas ownership.

DEVONIAN SHALE

RESOURCE

The principal known deposits of Devonian Shale gas are concentrated in the Appalachian, Michigan, and Illinois basins in the eastern United States. The study recognized differences in the thickness and gas content values of the deposits by delineating the black and gray shale horizons. The black shales have a higher gas content than the gray shales and are generally believed to be the predominant source beds of the natural gas found in the shales. Although the average total thickness of the shale deposits in the Appalachian basin is many times greater than that found in the other two basins, a large part of the deposit consists of the poorer quality gray shales.

The in-place gas resource was calculated on a volumetric basis using the appropriate gas content values for the gray and black shales. Among the three basins, the Appalachian basin has the greatest resource potential, varying from 225 TCF if only the black shale as determined by log analysis is considered, to 1,861 TCF if both black and gray shales based on sample thickness are used. Estimates for the Michigan and Illinois basins were 76 TCF and 86 TCF, respectively. The in-place gas is not a recoverable resource, but rather provides a means of ranking the shale gas potential of the three basins.

EXPLORATION REQUIRED TO LOCATE THE BETTER RESOURCE

If future Devonian Shale exploration does occur on a large scale, it would probably expand in the Appalachian basin as there is already significant shale gas production; therefore, for the purpose of this study, the projections of the potential for recoverable gas were confined to the Appalachian basin. Although similar projections could have been made for the Illinois and Michigan basins, estimates based on such limited data would be highly speculative.

METHODS OF RECOVERY AND STUDY METHODOLOGY

Historical production data from approximately 2,700 out of some 9,000 Devonian Shale wells in the four-state area of Kentucky, West Virginia, Ohio, and New York provided a substantial data base in developing the methodology for future production. A production model using a hyperbolic decline configuration allowed well performance to be represented by a single variable. The black shale thickness and well performance provided the correlation to predict potential production from estimates of the black shale thickness in the undrilled areas, taking into account such parameters as well spacing, success ratio, and lands accessible for future drilling. The predicted well performance, extracted from historical data, represents the proven state-of-the-art "traditional" technology. This technology could be considered more certain than the other two higher levels of technology presented in the study. Conventional technology represents the next level beyond traditional and is defined as improvements in technology which could reasonably be expected to occur. This was achieved by upgrading the traditional well performance based on well stimulation results published by E. O. Ray (1976). The source of well data in Ray's analysis was the primary shale-producing areas and it remains to be determined whether similar improvements can be achieved in the other shale areas. The third level of technology, identified as the advanced technology case, was developed from very limited stimulation and exploration research results. From this data it was assumed that advanced technology would double the improvement of conventional technology over traditional technology. This achievement would in all likelihood require significant breakthroughs in either or both production and exploration techniques.

RESULTS

The potential additions to reserves that may possibly be developed at various price levels, ranging from \$2.50 to \$9.00 per MMBtu, were determined as a function of rate of return (ROR) and technology in constant January 1, 1979, dollars. At a 10 percent rate of return, the estimated recoverable reserves under traditional technology at a price of \$2.50 per MMBtu is 3 TCF; this increases to 39 TCF at the maximum price of \$9.00 per MMBtu with advanced technology.

The prices at which supplies could be developed represent the field price paid to the producer exclusive of compression and suction pipeline facilities. If these facilities are taken into consideration, the incremental add-on cost would range between \$0.49 and \$0.68 per MMBtu at the \$2.50 and \$9.00 price levels, respectively.

Possible production volumes available from the estimated potential reserves were derived as a function of the drilling activity. The moderate drilling scenario assumed that the number of rigs would increase at a rate of 12 percent per year; this reflects the rig growth rate experienced in the Appalachian basin between 1973 and 1979. Under this drilling schedule, 9,000 productive shale wells would be in place by 1990 with annual production of 140 billion cubic feet (BCF) assuming conventional technology. By the year 2,000, there would be 36,000 wells producing at a yearly rate of 470 BCF. Considering the same drilling schedule but different technologies, production in the year 2000 would be 380 BCF for traditional technology and 600 BCF for advanced technology.

A second drilling schedule (high rig growth) was developed to illustrate the required drilling activity to develop essentially all of the Devonian Shale reserves priced up to and including \$9.00

gas during the next 20 years. With conventional technology, production in 1990 would be 550 BCF from 37,000 producing wells and would increase to 1,000 BCF per year from 126,000 wells by the year 2000.

CONSTRAINTS

Significant portions of the presently economically competitive Devonian Shale areas are under lease and demand will dictate when the gas will be produced, irrespective of price. Other areas lack immediately available pipelines. These two constraints are barriers to the immediate development of Devonian Shale. Several economic factors represent additional constraints: the 10 percent ROR, which is considered representative of low-risk production, may not be sufficient for drilling in the unproven areas, and current supplies of gas are suppressing field prices for natural gas. Also, the gas pricing structure under the Natural Gas Policy Act has not been in effect long enough for production buildup, and production will probably come first from the tight sandstone formations rather than from the more risky Devonian Shale.

Environmental and legal constraints are not major problems and can be dealt with in the normal course of exploration with a minimum of delay. Socioeconomic considerations are beneficial to a region which is economically depressed, although some temporary delays in obtaining adequately trained personnel may develop. If historical trends are realistic predictors, neither rig availability nor investment capital would constrain development.

MAJOR UNCERTAINTIES

The major uncertainties to the rapid development of Devonian Shale are primarily technical in nature. Exploration procedures for locating natural fractured shale are poor, conventional stimulation techniques have not been demonstrated with certainty, and present logging techniques often give ambiguous results when identifying potential producing zones. There is considerable uncertainty as to the amount of technically recoverable gas since much of the Devonian Shale resource is not only unproved but not drilled. Whether the projected estimates of gas can be produced will depend upon the demonstration of feasible extraction and exploration technology.

GEOPRESSURED BRINES

RESOURCE

Geopressured brine reservoirs are underground reservoirs which contain hot salt water at a pressure gradient greater than .465 pounds per square inch (psi) per foot of depth. The resource base is huge. Geopressured brine reservoirs are known to exist in the Tertiary deposits of the Louisiana-Texas Gulf Coast; the Mississippi Salt basin of Mississippi and Alabama; deep Mesozoic formations of the San Joaquin Valley of California; the Wind River, Piceance, Green River, Uinta, and Big Horn basins of the Rocky Mountain area; and the Tuscaloosa-Woodbine formation along the Gulf Coast.

Based upon extensive geologic data, the Louisiana-Texas Tertiary trend has by far the most potential and provides the best opportunity for resource development. This trend exists in a band approximately 50 to 70 miles wide straddling the coastline from southern Texas to the mouth of the Mississippi River. The sediments are known to exist to a thickness of 50,000 feet; however, the actual prospective reservoir thickness would be from 500 to 1,000 feet. In this study, these brines are assumed to be saturated with natural gas.

EXPLORATION REQUIRED TO LOCATE THE BETTER RESOURCE

The large existing data base for Tertiary sandstone reservoirs in the Gulf Coast area has enabled geologists to locate the best prospects for development. This data base, which results from more than 10,000 penetrations to explore for and develop geopressured oil and gas reservoirs, has provided knowledge of:

- Reservoir temperature
- Reservoir pressure
- Reservoir quality
- Cost data.

Several factors critically important to commercial development and production of geopressured brines are not known and must be resolved. These factors are:

- Continuity of the reservoir within a fault block
- Amount of natural gas and minerals in solution in the brine
- Recovery factor.

The Department of Energy wells of opportunity and design test wells programs have in the past and will continue to obtain data in these uncertain areas.

METHODS OF RECOVERY

Development of a geopressured brine reservoir would consist of drilling and then producing, by natural flow, the hot salt water from deep wells; conversion of the geothermal energy to electricity (when economic); separation of the methane from the water; sale of the methane; and underground disposal of the produced water.

STUDY METHODOLOGY

The study participants made a detailed engineering appraisal of the 11 best prospects identified by the University of Texas and Louisiana State University under the funding of the Department of Energy.

These prospects were examined in detail to determine the following:

- Reservoir performance
- Drilling programs
- Production and water disposal methods
- Geothermal and hydraulic energy potential
- Producing rates and recoverable reserves
- Cost estimates and economics of field development.

RESULTS

Based upon the 11 best prospects and on an extrapolation of their data, it was concluded that it is possible to develop and produce some geopressured brine reservoirs at gas prices ranging from $4.00 to $9.00/MCF at a 10 percent (real) rate of return on investment.

The most optimistic case predicted gas rates of 54 MMCF per day in 1990 and 81 MMCF per day by the year 2000. Ultimate recovery for this case would be 568 BCF.

The less optimistic, "Lower Median Case," which appears to be the most likely from tests conducted thus far on two Department of Energy wells of opportunity and one design test well, predicts sales gas rates of 18 MMCF of gas per day by 1990 and 23 MMCF of gas per day by the year 2000. Ultimate recovery from this case would be 240 BCF.

CONSTRAINTS

No technical constraints to drilling and producing geopressured reservoirs were found. Locating large fault blocks containing sands of high permeability is the major problem in achieving significant production.

MAJOR UNCERTAINTIES

The major uncertainties in geopressured brine development are:

- Reservoir continuity within a fault block
- Reservoir quality
- Recovery factor
- Possibility that the geopressured brines are saturated with methane
- Sand production
- Corrosion
- Scale.

The current Department of Energy test program is aimed at resolving some of these uncertainties.

BACKGROUND

For the purposes of this study, tight gas is defined as natural gas in either blanket 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 at prior gas prices due to the low natural flow rates of the gas.

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 at many times the rate that an unfractured well can. 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.

It has been estimated that by 1978 as much as 0.8 TCF per year was being produced from tight gas formations. 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 (lower 48) thought to contain prospective 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.

Potential ultimate recovery was 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. The gas prices examined were assumed to be effective immediately and to remain constant throughout the time period. 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 can now be made 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. Well spacing for advanced technology averages about 106 acres, or six wells per section.

Possible producing rates for the total tight gas resource were calculated under several scenarios, incorporating various development schedules and economic assumptions.

RESULTS

Tight Gas Resource and Recovery

The study indicates that 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.

The U.S. tight gas resource and the amount expected to be recoverable for both the appraised and extrapolated areas are summarized in Table 4. 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 4 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.

The results show that a potential recovery of 290 TCF is available at the present incentive price of $3.33/MCF and base technology. At $5.00/MCF the base case potential should increase to 365 TCF, and if advanced technology is achieved, the potential could rise to 503 TCF.

TABLE 4

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

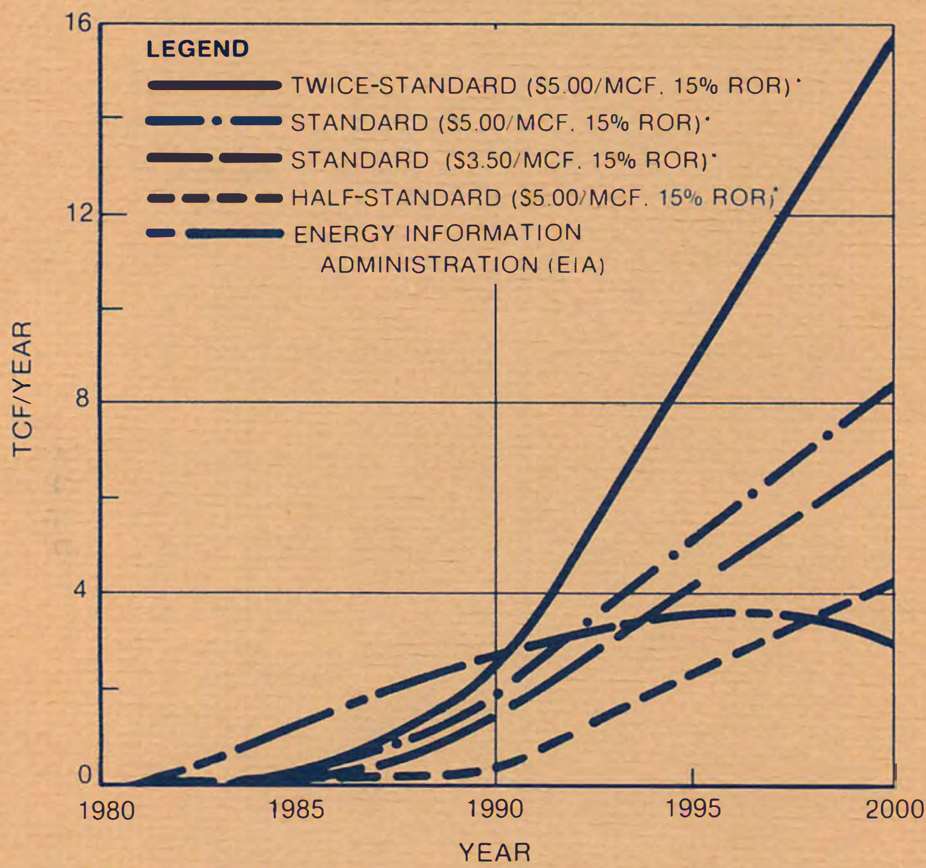
	Appraised (12 Basins)	Extrapolated (101 Basins)	Total*
Prospective Area (Sections)	359,500	655,000	1,014,500
Productive Area (Sections)	53,000	68,500	121,500
Total Gas in Place (TCF)	444	480	924
Maximum Recoverable (TCF)	293	315	608
Base Technology -- Recoverable (TCF)†			
@ $2.50/MCF	97	95	192
$5.00	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.
†15 percent discount rate of return and constant January 1, 1979, dollars.

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, which is described in Volume V, assumes a specific development schedule of prospects and a phasing-in of advanced 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 recompletion in existing wells. Results were found to be relatively insensitive to rate of return. For this reason, a 15 percent rate of return was used for most calculations.

Figure 3 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 above scenarios do not include gas produced from recompletions. A schedule that adds gas from recompletions in the Southwest region to the half-standard scenario was also calculated. It agrees reasonably well with the projection of the Energy Information Administration (EIA curve in Figure 3).



*Constant January 1, 1979, dollars.

Figure 3. Tight Gas Production Rates — Comparison of Scenarios.

With the standard scenario and a 15 percent rate of return, annual tight gas production in the year 2000 could reach about 7 TCF at a $3.50/MCF gas price and 8 TCF at $5.00/MCF. At the standard scenario and a 10 percent rate of return, annual production in the year 2000 could reach 10.5 TCF at a $9.00/MCF gas price. Furthermore, the cumulative amount of tight gas recovered by the year 2000 would only be about 10-15 percent of the recoverable U.S. resource. Tight gas could be produced at an annual rate of 8 TCF or more until 2030 and at a declining rate until 2070.

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 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 appraised in the chapters of Volume V, Part II. Estimates of net pay, porosity, production rates, probability of success, investment requirements, and average rates of return for 82 subbasins are discussed in the text and 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. Formations having favorable geochemical and thermal history for gas generation are often 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. Better quality reservoir rock is searched for by drilling along natural fracture concentrations, following lenticular reservoir trends, 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 in Volume V, Part II reflect that experience in terms of economics and risk.

The risk involved is reflected in the value of the percentage of prospects estimated to be profitable 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

Potential constraints to the development of tight gas were examined; the results are shown below:

- 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 supply of investment funds will be large enough to meet the anticipated demand for tight gas exploration and development.

- A major portion of the tight gas potential is on federal lands. Federal lands proposed for withdrawal, and those already withdrawn from energy and other uses, could reduce the potential tight gas resources available not more than 4 or 5 percent in the lower 48 states.

- Environmental considerations were not thought to be a constraint to increased tight gas development and use.

- 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 major potential constraint appears to be limited pipeline capacity in the Rocky Mountain and Northern Great Plains/Williston areas.

MAJOR UNCERTAINTIES AND RESEARCH AND DEVELOPMENT NEEDS

Uncertainties in Determining Characteristics of Tight Gas Formations

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 sufficient data to 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 massive hydraulic fracturing (MHF) technology and support accurate assessment of the geologic risks of a prospect.

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 currently exist for direct measurement of fracture width or length. 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. Research progress has been 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.

From advanced technology and closer well spacing, over a 40-year period about $100 billion of additional net revenue could accumulate as a result of advanced technology; this has a present value of $5.4 billion. The industry would need to spend approximately $1.5 billion for research and field tests over a 15-year period to bring this about. These costs, with a present value of $570 million, could be recovered (undiscounted payout) in about nine years. At a 50 percent probability of success, the payout time would be extended to about 12 years.

APPENDICES

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

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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