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BY THE COMPTROLLER GENERAL

Report To The Congress

OF THE UNITED STATES

Help For Declining Natural Gas Production Seen In The Unconventional Sources Of Natural Gas

Oil imports could be reduced and domestic gas production increased if additional gas production is obtained from four unconventional resources--eastern Devonian shales, tight sands, coal beds, and geopressured zones.

Gas produced from these resources can help maintain overall production levels as supplies from conventional gas sources gradually decline.

The eastern shales and western sands are the chief potential contributors in the near term. Further demonstrations of coal bed methane's recovery feasibility could improve the prospects for its production while future geopressured methane production remains speculative at this time.

UNITED STATES GENERAL ACCOUNTING OFFICE

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COMPTROLLER GENERAL OF THE UNITED STATES
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To the President of the Senate and
the Speaker of the House of Representatives

This report discusses four unconventional sources of natural gas and the prospects that gas from these resources can help supply the country with needed fuel. The report notes that gas produced from the unconventional gas sources could help to maintain overall gas production levels. Observations are included on technical progress required to increase gas recovery and Federal incentives for encouraging the use of these resources.

We are sending copies of this report to the Secretaries of Energy and the Interior, and to interested congressional committees.

Elmer B. Staats
Comptroller General
of the United States

PL. 95-621
pg32

Gas resources
Coal resources
Mining industry
Fossil fuels

COMPTROLLER GENERAL'S
REPORT TO THE CONGRESS

HELP FOR DECLINING NATURAL GAS PRODUCTION SEEN IN THE UNCONVENTIONAL SOURCES OF NATURAL GAS

<u>DIGEST</u>

Natural gas provides about 25 percent of the Nation's energy; 19.8 trillion cubic feet of gas was consumed during 1978. But, gas supplies from conventional sources are expected to decline as GAO described in a recent report "Analysis of Current Trends in U.S. Petroleum and Natural Gas Production" (EMD-80-24, Dec. 7, 1979). Consequently, the unconventional gas sources have been receiving additional attention.

Unconventional gas resources can contribute to the Nation's future supplies and help maintain overall production levels as supplies from conventional sources gradually decline. Gas from the eastern Devonian shales and western sands are the chief potential contributors to unconventional gas production in the near term. The prospects of coal bed methane production will improve if further demonstrations verify that recovery is technically feasible and economically competitive. The prospects for geopressured methane production remain speculative at this time.

<u>NATURAL GAS FROM THE EASTERN SHALES</u>

Large quantities of natural gas are contained in the eastern Devonian shales located from New York to Alabama with similar deposits in Illinois, Indiana, and Michigan. The estimated resource base has ranged between 10 and 700 trillion cubic feet and the wide range of variations in the resource estimates indicates uncertainty in the resource size. (See pp. 4 and 5.)

Low shale well production rates have been the principal deterrent to increased industry

Nat gas production — long term

gas resources
fuel supplies

EMD-80-8

activity in shale areas. This condition has favored investments in conventional gas exploration where wells have recovered investment costs in less than half the time required for shale gas wells. (See pp. 5 to 7.)

As much as 1 trillion cubic feet per year can be produced in the 1990s according to the Office of Technology Assessment and a report prepared for the Department of Energy. This compares with current production estimated at about 0.1 trillion cubic feet. However, economic and technical uncertainties must be resolved to realize this large an increase in production. (See p. 12.)

Although there are uncertainties, the November 1979, price decontrol permitted by the Natural Gas Policy Act of 1978 appears to make additional shale prospects commercially attractive. The Congress is also considering a tax credit of $0.50 per thousand cubic feet which would be available if drillers selected to price shale gas production at regulated prices. (See p. 11.)

NATURAL GAS FROM THE TIGHT SANDS

Twenty tight gas basins identified to date stretch from New Mexico into Canada and eastward into Arkansas and Louisiana. Estimates of the recoverable gas are uncertain and range from 25 to more than 600 trillion cubic feet. Cumulative gas production from tight sand areas exceeds 12.5 trillion cubic feet; about 85 percent of the production is from one type of tight sand deposit described as blanket shaped and generally considered commercial. Current annual production from the tight sand areas is over 0.85 trillion cubic feet per year which is about 4.5 percent of total U.S. gas production according to the Department of Energy. (See pp. 14 and 15.)

It has been estimated that as much as 7.7 trillion cubic feet of gas could be produced annually from 14 of the 20 basins by 1990 which includes the blanket deposits. Obtaining added production will require continued increases from the commercial blanket sand areas and technical improvements which will permit commercial production from the other types of deposits. (See pp. 15 and 16.)

The Natural Gas Policy Act does not require decontrol of the price of tight sand gas in November 1979 but the Federal Energy Regulatory Commission could allow higher prices for tight sand gas production as a result of on-going proceedings. If the Commission does not take this action, the Administration plans to ask the Congress to consider legislative action to decontrol prices. Providing additional incentives for production should accelerate industry activity in the tight sand gas basins. (See p. 19.)

COAL BED METHANE

The coal beds of the United States contain significant quantities of methane. Estimates of recoverable coal bed methane are speculative and range from 2 to 478 trillion cubic feet. (See p. 20.)

While some data on eastern minable coal bed methane are available for analysis, insufficient information is available to judge the overall quality and quantity in western coal. (See p. 21.)

This resource might be used as a local source of gas supply, but sufficient demonstrations to verify this possibility have not yet been performed. In addition, the natural gas industry has made few attempts to recover coal bed methane and there are unresolved legal questions about gas producer and coal company ownership rights. (See pp. 21 and 22.)

Methane drainage techniques to reduce the quantities of methane in underground coal mines have been developed by the Department of the Interior's Bureau of Mines as a safety precaution. These techniques could also be used to capture the methane as an energy source, but they have not yet been widely adopted. (See pp. 25 and 26.)

Some coal bed methane production appears feasible with price decontrol, but further development and demonstration appears necessary to attract widespread industry or community interest. Decontrol could develop added interest in this resource. Further production incentives such as the tax credit of $0.50 per thousand cubic feet now being considered by the Congress could also increase interest in this resource. (See pp. 26 to 28.)

THE METHANE (NATURAL GAS) OF GEOPRESSURED ZONES

Several initial estimates of the geopressured resource base (hot, pressurized, briny waters containing methane) for the Texas and Louisiana Gulf Coast area have been vast. But, the important question is the amount that can be economically recovered. This question can only be answered by further research and development. (See pp. 34 and 35.)

Due to the uncertainty of geopressured methane's potential, this resource is too speculative to depend on as a major contributor to the Nation's energy supplies at this time. DOE estimates that the commercial potential of the resource is not expected to be known until the mid-1980s. Even though the recoverable resource may be lower than some of the high initial estimates, this resource continues to merit attention in the Department of Energy's research and development program. However, the proposed $0.50 per thousand cubic feet tax credit may not result in commercial production at this time because production of this resource has not been demonstrated, the costs of production are speculative, and industry believes that research and development is appropriate at this time given the high potential costs and risks associated with production.

AGENCY COMMENTS

The Department of Energy, including the Federal Energy Regulatory Commission and the Department of the Interior, Bureau of Mines and Geological Survey, commented informally on a draft of this report. Both agencies generally agreed with the report contents and their comments are considered as appropriate.

Contents

ABBREVIATIONS

DOE Department of Energy

FERC Federal Energy Regulatory Commission

mcf thousand cubic feet

tcf trillion cubic feet

CHAPTER 1

INTRODUCTION

Despite past shortages and declining production the possibility of increased natural gas sales through the end of this century are being discussed. However, if production continues to decline or if gas sales increase, the United States will increasingly rely on alternative sources of gas supply. Several of these sources would be foreign, such as imports of gas from Canada, Mexico, and the Organization of Petroleum Exporting Countries. Other sources, such as coal gasification and the unconventional gas sources would be domestic.

Over the past several years the Nation has produced and consumed natural gas at a faster rate than it has discovered new reserves. The Nation has proven gas reserves estimated at 200 trillion cubic feet (tcf) which will be consumed in about 10.5 years at the current rate. Yearly additions to U.S. reserves have been declining, and a long-term reversal of this trend is generally not expected.

To return to lower-48 gas production of about 20 tcf per year would require the discovery of almost 15 tcf per year of new gas reservoirs for about 4 or 5 years. Most consider such a level of discoveries very unlikely. Since discoveries averaged 4 tcf between 1967 and 1976, such a discovery rate would imply finding at least 4 or 5 new reservoirs or fields over the period with reserves on the order of 10 tcf each. The Gomez field of West Texas is the only field 10 tcf or larger discovered since 1945 in the lower-48. Further, there have been only 2 fields between 4 and 10 tcf discovered during the same period.

Assuming an extremely high rate of discoveries in response to higher natural gas prices, the American Gas Association estimated that lower-48 production will be about 18.6 tcf in 1985 and 19.4 tcf in 1990. However, the Association's projections show that additions to reserves will peak in 1983 at 20.0 tcf and fall to 17.3 tcf in 1990. These declines in reserve additions would eventually be reflected in production decreases.

The Conference Committee report on the Natural Gas Policy Act of 1978 (Public Law 95-621) shows that the deregulation provisions of the act are not expected to reverse the expected production decline in the long run. 1/ According to the report, production from the lower-48 States is expected to be about 16.6 tcf in 1985.

The recent increased gas supply situation has not changed our expectation of declining production. The current supply situation has been brought about by the curtailments and fuel switching of previous winters and the availability of added gas supplies from the intrastate markets. Because no fundamental changes in domestic natural gas production have contributed to the current level of supplies, this supply situation should be considered temporary.

Some of the Nation's natural gas customers must switch to other fuels or rely increasingly on alternative sources of natural gas in the future. This trend has started already. Previous gas production losses have been replaced by imported oil or by switching to coal, electricity, or other fuels. For example, about one half of the oil import growth from 1974 through 1977 has been directly attributed to declining natural gas production, according to the American Gas Association. Also, the United States continues to import gas from Canada and has negotiated purchases of Mexican gas.

However, importing natural gas and oil contributes to the United States balance of payments deficit. For example, if domestic gas supplies are 1.5 tcf greater in 1985 than they would otherwise be, U.S. oil imports could be reduced up to 750,000 barrels per day. This would represent about 12 percent of our total oil imports and, based on the cost of oil at $20.00 per barrel, could contribute up to $5.5 billion toward improvement in our balance of payments.

Even though the United States may continue to purchase oil and gas from foreign sources, imports could be reduced to some extent by (1) greater conservation, (2) increased U.S. oil and gas production, and (3) conversion to alternative domestic supplies such as coal and renewable energy sources. Within that framework, the major options for maintaining domestic gas production past 1985 appear to be limited to new conventional sources, such as the Outer Continental Shelf, coal gasification, and producing gas from deposits which are usually termed unconventional natural gas sources. Continued gas production enables the Nation to take advantage of the substantial pipeline network and

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1/Joint Explanatory Statement of the Committee on Conference, p. A-14.

infrastructure of the gas industry. For the Department of Energy (DOE) to push immediate commercialization of the unconventional gas sources successfully, technical feasibility and profitability should be demonstrated.

This report discusses the following four unconventional gas sources:

--The gas-bearing Devonian shales of the eastern United States.

--The low-permeability or "tight" gas sands of the Rocky Mountain Region.

--The methane contained in coal beds.

--The methane contained in the geopressured aquifers of the Gulf Coast Region.

SCOPE OF REVIEW

We interviewed DOE officials responsible for the activities discussed in this report, contractors involved in DOE's research, development, and demonstration programs, other Federal agency officials, representatives of various energy organizations and institutions, and knowledgeable academicians and industry officials. We also reviewed numerous studies and publications relating to the subject matter.

The report identifies industry's interest in the unconventional gas resources, the status of technical developments for recovering the resources, the size of the resource bases, and the extent to which these resources may be produced. The report also identifies the factors which are the most important considerations for future development. We did not attempt independent analyses of the resource sizes, future production potential, or the relationship between gas market prices and future gas production.

The Department of Energy, including the Federal Energy Regulatory Commission, and the Department of the Interior, Bureau of Mines, and Geological Survey commented informally on a draft of this report. Both agencies generally agreed with the report contents and their comments are considered as appropriate.

CHAPTER 2

NATURAL GAS FROM THE EASTERN SHALES

The eastern Devonian gas shales are located in an area from New York to Alabama and extending westward to Ohio, Kentucky, and Tennessee. Similar deposits occur in Illinois, Indiana, and Michigan. They contain sizeable volumes of natural gas. Industry interest in Devonian shale gas areas is evident, but generally low gas recovery rates have prevented widespread development. DOE is attempting to improve the recovery rates, and the price of shale gas has recently been deregulated. Based on technical feasibility, the prospects for profitable operations, and industry interest, gradual increases in natural gas production from the eastern shales could be forthcoming.

THE RESOURCE BASE

Close to urban and commercial centers in the eastern United States are shales containing an abundant accumulation of natural gas originating from the decomposition of plant and marine life. The gas has been used as fuel by a few resourceful individuals, gas utilities, and independent producers since 1820. Annual Devonian shale gas production is about 0.1 tcf and cumulative production is about 3.0 tcf.

The Devonian shales derive their name from the geologic period in which they accumulated some 350 million years ago. Some geologists believe these shales may extend over a 500 thousand square mile area from the Appalachians to the Rocky Mountains and from Canada to Mexico. Major concentrations of current interest are located from New York to Alabama, and extend westward into Ohio, Kentucky, and Tennessee, with similar deposits in Illinois, Indiana, and Michigan.

Available evidence indicates that virtually all Devonian shale contains some gas, and its gas-producing ability is generally indicated by color which ranges from gray to deep brown to black. The black and very dark brown shales are generally believed to be better gas producers and brown shale areas support most commercial wells today.

Estimates of the Devonian shale gas resource base vary considerably as well as the amounts which are recoverable. Before DOE's research and development program, the resource base had been estimated to range from 75 to 700 tcf. Recently, officials of the Department of the Interior's

Geological Survey, involved in mapping and characterizing this resource as part of the DOE program, made a preliminary resource estimate of 10 to 520 tcf. The range of these resource estimates reflect that a high degree of uncertainty continues to exist.

In many areas the concentration of free gas within the shales may be too low to be produced at reasonable prices. Some experts have estimated that only 10 percent of the shale gas can be recovered due to low concentration. In contrast, typical oil and gas reservoirs may produce 40 to 60 percent of the total resource in place. Further testing of the resource is needed to obtain better estimates of the amounts of gas which are recoverable.

INDUSTRY PERSPECTIVE

The gas industry has drilled over 8,300 wells in the Big Sandy Devonian shale gas field of eastern Kentucky, and about 4,600 in areas of other eastern States which contain shale deposits. Although data from some of these wells have been used for evaluating shale gas well profitability and future production, all of these wells cannot be classified as shale gas producers. Other gas producing strata above or below the Devonian shales are important contributors to the gas supplied by these areas.

Because there are other gas producing strata in shale gas areas, a Federal Energy Regulatory Commission (FERC) official said it may be difficult for a producer to determine if wells in shale areas are producing gas only from the Devonian shale or from both shale and other producing strata at the same time. When such situations occur it will be difficult to apply consistent regulatory treatment. A method for resolving this question has not been developed.

The shale deposits which have been analyzed show that gas is trapped tightly in the shale itself, and the shale provides only small spaces to hold gas or other substances. Thus, the ability of gas to flow through the small spaces in the shale is low. Flow through a porous medium is termed permeability, and low permeable substances offer great resistance to the free flow of gas. The permeability of shale deposits has been shown to be 2.5 to 1,000 times lower than typical oil and gas producing deposits. 1/

1/The permeability of typical oil and gas bearing strata ranges from 5 to 2,000 millidarcies; Devonian shale ranges from 0.001 to 2 millidarcies.

Measures of shale porosity, or the extent that pores within the shale are filled by gas, indicate that porosity levels are 4 percent or less. Typical producing formations are 8 to 30 percent.

These characteristics of gas-bearing shales vary. Some shale deposits have such low quantities of gas or potential for releasing gas that they can never be produced. In other deposits, these conditions result in slower gas recovery rates than from conventional reservoir rocks even though shale wells are fractured. Although shale gas wells have produced at slower rates than industry norms, they continue to produce gas at relatively constant rates for extended periods of time. But, this is not as attractive as conventional gas deposits which pay off investment costs in less than half the time required for shale gas wells. Nonetheless, some companies have found that shale gas wells can be profitable.

The Columbia Gas System Service Corporation, one of the largest corporations involved in shale gas production provided us with examples of shale well economics. Its information is based on production data for about 2,000 wells and prices set before passage of the Natural Gas Policy Act of 1978.

Columbia found that most of its shale gas wells have produced at commercial rates for more than 35 years. However, the shale wells have provided a low return on investment compared to conventional wells. Also, the break-even point for investments in shale wells has been different. The company can recover the cost of establishing a conventional well in less than 2 years, in contrast to its shale wells which require about 5-1/2 years to recover initial investment costs.

This slow rate of recovery appears to be an important consideration to the driller exploring for gas in the Appalachian region. Because these drillers are typically small independent operators, they usually lack the resources to assume risks greater than the industry norm. If an operator's financing arrangements are set with the expectation of conventional well payoff times, shale wells will not appear to be an attractive investment.

If technical improvements in shale well fracturing methods increase the initial gas recovery rates without decreasing long-term production, shale well profitability will improve. The goal of fracturing is to open fractures or joints in the shale so gas can flow more readily into the well. Two basic fracturing methods have been used; they are, applying hydraulic pressure and setting off explosions in the wells. There are several methods within these two categories and further variations within each method.

For example, hydraulic fracturing can be carried out with water, foam, or liquefied gas. In each hydraulic fracturing treatment, a variety of ingredients such as sand, water, and chemicals are injected into the shale after drilling. A basic variation of this method is massive hydraulic fracturing which includes higher injection rates and larger quantities of fluid than regular hydraulic fracturing treatments. The choice of fracturing method and mix of ingredients for Devonian shale is site-specific and there is no agreement whether hydraulic or explosive fracturing is generally the better method. Both methods are currently in use, and DOE is testing variations in fracturing methods to improve shale gas recovery rates.

Technical variations in drilling are also being considered as potential methods for improving shale gas production. For example, deviated drilling, or drilling at an angle less than perpendicular, is being attempted by DOE and private industry to intersect more sets of natural fractures and to increase the potential area of gas drainage. Although more costly than vertical drilling, it is hoped that such wells will increase gas flow. Further experimentation and production history is required before advanced drilling and stimulation practices are regarded as reliable, effective methods improving shale well gas production.

GOVERNMENT ACTIONS TO SPUR PRODUCTION

The Government has taken two major actions to spur the commercial development of this resource. In 1976, DOE initiated the Eastern Gas Shales Project to perform research, development, and demonstration activities. The second major action was the decontrol of Devonian shale gas prices as part of the Natural Gas Policy Act of 1978. 1/ Several

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1/After November 1, 1979, gas producers may charge deregulated prices following (1) submission of documentary evidence describing qualifying gas bearing deposits to the appropriate jurisdictional agency, (2) approval by the jurisdictional agency, and (3) approval by the Federal Energy Regulatory Commission. See the Natural Gas Policy Act sections 107(c), 121(b), and 503 and the Federal Energy Regulatory Commission's Interim Rules of October 29, 1979, "Defining and Deregulating Certain High-Cost Natural Gas."

additional options also remain open for Government action including variations in DOE's research and development program and the addition of financial incentives. The rural development proposals of the Administration would also provide incentives for small rural communities to use these resources. This program is described further on page 11.

The Eastern Gas Shales Project

Three important issues are being addressed by DOE in this project: How much gas is contained in the shale? Where is it located? How can it be developed commercially? The project was designed as an 8-year effort to develop the information and technology needed to attract large-scale commercial production of shale gas. About 35 organizations including State geologic survey teams, universities, private research laboratories, and gas companies are participating in the project along with the U.S. Geological Survey. DOE's proposed budget for the complete project was $135 million, with industry contributing an additional $45 million. The project is scheduled for completion in 1984.

The project includes efforts to inventory and characterize the shale resources, improve and test well completion methods, and disseminate the results to industry. The first effort is designed to determine the characteristics of the resource, the resource's location, and the quantity which is in place. The second effort is designed to increase the profitability of shale fracturing methods. In addition the project had several specific goals:

--To increase the average open-flow production rate of new shale wells from 100 to 300 thousand cubic feet or more of gas per day.

--To increase the average total gas reserves added per well drilled from 300 to 600 million cubic feet.

--To add 3.5 to 7.0 tcf of gas to the proven reserves in the Appalachian basin by 1985.

According to several gas industry officials, these goals are reasonable, achievable, and adequate to stimulate significant growth in gas production from the Devonian shales.

Department of Energy officials informed us that the specific goals cited above have been eliminated and that general goals will be adopted during late 1979 or early 1980 with the publication of an unconventional gas resources research and development plan. Specific goals such as the ones cited above will not be adopted because (1) production and related developments such as reserve additions are dependent on changing economic factors which cannot be controlled by the research and development process, (2) research progress is dependent upon funding but, the annual research budget is not strictly tied to the production potential of one resource, and (3) forecasting production increases which may result from research is a far more difficult task in a resource area which depends upon drillers discovering gas than in other areas such as synthetic fuels where production is dependent upon the operation of a specific number of industrial plants.

We recognize that the precise effects of research and development may be difficult to identify separately from other physical, economic, or policy factors associated with future production. However, we believe that the research and development program can and should identify specific cost-related objectives which that program is designed to achieve. For example, to the extent that the program is designed to increase gas flow rates, these flow rates and the costs of achieving them should be identified. Specifying such goals would help DOE achieve greater accountability for its research and development program.

Setting specific goals could also help to provide the Congress greater assurance that program funding is properly balanced among competing research and development programs. Our report, "Fossil Energy Research, Development, and Demonstration: Opportunities For Change" (EMD-78-57, Sept. 18, 1978) points out that a formal system of priorities, as well as detailed cost objectives, would give the Congress a better basis for evaluating the adequacy of required funding levels for DOE's fossil program or for funding alternative approaches. We believe the establishment of specific program goals is an important step in the priority setting process as suggested by our previous report.

Through fiscal year 1978, the Government has spent $35.5 million and industry has contributed an additional $8 million. Officials of DOE and the U.S. Geological Survey who are coordinating the resource characterization and mapping work are due to complete the work during fiscal year 1980. The U.S. Geological Survey will make another estimate of the resource before completion.

As of March 1979, 34 wells have been completed and evaluated by the Eastern Gas Shales Project. Twenty of the wells showed increased gas flow rates following a fracturing treatment, and 14 wells were classified as unsuccessful.

The results to date indicate that the preferred stimulation method is hydraulic fracturing in areas where the shales have a low level of natural fractures. In areas with a high level of natural fractures, explosive stimulation appears to be the preferred method. The cost of recovery so far has ranged from $2 to $6 per thousand cubic feet (mcf). This price range indicates that some areas may be commercial, but further improvements in flow rates are still needed to make large areas commercial.

DOE's fiscal year 1980 budget proposes a $9 million reduction from the $18 million budget of fiscal year 1979. This budget cut reflects the advanced status of resource characterization, the state of technical development compared to the other unconventional resources, and the expectation of additional production due to the Natural Gas Policy Act.

Devonian shale gas
prices decontrolled

The study performed by the Office of Technology Assessment 1/ and two 1978 studies performed for DOE indicated that prices between $2 and $3 per mcf should be sufficient to cover the costs of shale gas production in some areas. 2/ Prices above $2.00 may now be charged according to the Natural Gas Policy Act of 1978 since Devonian shale gas prices have been decontrolled. Under decontrol, the incremental pricing rules require that certain production costs must be passed-through to industrial consumers; but, shale gas pricing can now be determined by market decisions. 3/

Previous analyses show that decontrol should result in prices for Devonian shale gas which are sufficient to cover production costs. However, these analyses did not discuss

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1/"Status Report on the Gas Potential from Devonian Shales of the Appalachian Basin." Office of Technology Assessment, Nov. 1977.

2/The Office of Technology Assessment study used constant 1976 dollars as a basis for economic calculations while the other studies used constant 1977 dollars.

3/The incremental pricing rules prescribed in Title II of the Natural Gas Policy Act would operate to increase prices to certain industrial gas consumers until the price they pay equals an equivalent price of substitute fuel oil. This provision provides some protection against rapid price increases for residential gas users and others such as schools, hospitals, and agricultural facilities.

the effect of an incremental pricing provision on high cost gas. Several DOE officials said that the pricing provisions of the Natural Gas Policy Act are likely to increase attention on conventional gas deposits but not the unconventional deposits. This opinion is based on the theory that industry drillers will continue to be attracted to conventional deposits where payoff times are shorter due to higher gas flow rates, and risks are decreased due to familiarity with the resources.

<u>Other actions to spur development</u>

Additional financial incentives could be provided to accelerate industry drilling for Devonian shale gas and tax incentives can be considered an effective tool for reducing payoff times for Devonian shale wells. According to the Office of Technology Assessment, a 22 percent depletion allowance would be as effective as a price increase of $.50 per mcf. This would certainly affect the payoff time gap between a conventional and a Devonian shale gas well.

The President proposed a set of special incentives for the unconventional gas resources in May and July 1979. These include:

--a $0.50 per mcf tax credit which would be gradually reduced as prices increase so that at the world oil price equivalent of $28 per barrel no tax credit would be provided; and

--a $300 million grant, loan and loan guarantee program for rural communities to develop coal bed gas or Devonian shale gas projects if they would provide local benefits.

The decontrol of shale gas prices under the Natural Gas Policy Act may provide some incentive even though the precise effect of decontrol and the incremental pricing provisions on production cannot be predicted with certainty. The principal benefit of decontrol with incremental pricing and the proposed tax credit in the near-term would likely be accelerated exploration of shale gas areas and the additional resource knowledge that would result. If exploration of shale gas areas accelerates, additional gas production could follow.

The proposed grants, loans, and loan guarantees for rural committees are dependent upon the successful completion of a demonstration program. Demonstrations are being undertaken in six communities in areas where shale deposits and coal beds exist, to determine if dependable gas supplies can be developed for community use at competitive prices. A $700,000 grant has been made to the American Public Gas Association to initiate the six recovery projects. Details of the $300 million program, including funding requests, will be finalized following successful completion of the six demonstration projects.

FUTURE PRODUCTION POSSIBILITIES

As described above, the pace of industry's activity will be conditioned largely by shale gas quality, technical improvements, and gas pricing. These factors are interrelated and will, in combination, play a major role in determining the future of Devonian shale gas. Any estimates of future production are based on preliminary assessments of these factors, and numerous assumptions are made when projecting future production rates. The pace of industry activity could also be influenced by other factors including time required to obtain drilling permits and environmental clearances, obtaining legal rights to the gas, and the availability of workers and materials.

How much of the shale gas resource can be produced in the next 15 years? The Lewin report 1/ estimates that 0.7 to 0.9 tcf might be produced each year by 1995 based on prices up to $4.50 per mcf. Also, the study by the Office of Technology Assessment indicated that yearly production could reach 1 tcf about 1990, based on prices in the range of $2.00 to $3.00 per mcf. The study concluded that

> "There appears to be no practical way short of creating the economic incentives necessary to induce an extensive drilling effort, to ascertain whether the Appalachian Basin shale might actually contribute more, or less, than 5 percent of the total U.S. natural gas supply."

Accordingly, we believe that economic and technical uncertainties must be resolved in order to realize this production potential.

1/"Enhanced Recovery of Oil and Gas," Lewin and Associates, Inc., Feb. 1978, prepared for DOE.

CONCLUSIONS

Gas production from the eastern shales is commercial in some areas today. The principal deterrents to widespread investment in shale gas wells in the past have been traditionally low production rates and low gas prices. These conditions favored investments in conventional gas wells which recover investment costs in less than half the time required for shale gas wells. If DOE's research and development program and industry, acting both with DOE and independently, continue to demonstrate techniques which improve gas recovery rates within the range of competitive prices, investments in shale gas wells will be more favorable.

Changes in gas pricing are also affecting the profitability of shale gas wells. Decontrol of shale gas prices permitted by the Natural Gas Policy Act appears to make additional shale gas prospects commercially attractive. But, the effects of decontrol coupled with incremental pricing are uncertain.

CHAPTER 3

TIGHT SANDS NATURAL GAS

Twenty major "tight sands" basins with large amounts of natural gas stretch from New Mexico northward into Canada and eastward into Arkansas and Louisiana. Many sandstones in these basins also have a high resistance to gas flow which poses recovery problems. However, industry has been active in all types of tight sand deposits and gas from one type of deposit is produced in significant quantities. DOE is attempting to stimulate the development of the tight sand deposits which present great technical challenge. Based on technical feasibility, the prospects for profitable operations, and industry interest, continuing increases in production from tight sand areas can be expected.

THE RESOURCE BASE

The locations of tight sand gas deposits have been known for over 30 years, but with the exception of the most favorable areas, this resource has not been developed. The three basins with the greatest exploration history are in the Rocky Mountain area--the Piceance Basin of Colorado, the Green River Basin of Wyoming, and the Uinta Basin of Utah. These basins are commonly referred to as the Western Tight Gas Basins.

Drilling has occurred in many other tight sands gas areas. However, most were quickly described as noncommercial and little geologic data are available on these deposits in comparison to conventional oil and gas fields. Although the characteristics of these deposits vary considerably, they are generally classified in four ways:

--Tight Blanket Sands - blanket shaped, relatively continuous deposits of great lateral extent, often found at great depth. 1/

--Western Tight Basins - blanket and lens-shaped (lenticular) deposits.

1/There are no set industry standards for defining various drilling depths. However, one DOE official provided the following guidelines: shallow wells extend to 4,000 feet, medium depth to 10,000 feet, and deep wells below this depth.

--*Tight, Lenticular Basins* - in contrast to the Western Tight Basins these areas have larger lens-shaped deposits at shallower depths.

--*Shallow Basins* - shallow deposits which vary from blanket to lenticular.

--*Other* - reservoirs with special development and engineering problems.

Many of these basins cover large land areas, exploration data are limited and, consequently, the resource estimates vary widely. Estimates of gas in place are as high as 1,200 tcf and estimates of recoverable gas range from 25 to over 600 tcf. The Lewin report 1/ concluded that 14 of the tight basins contained 409 tcf of recoverable gas.

How much of this resource can be produced? Under favorable recovery and price assumptions some estimate that about half of this resource can be produced, including significant quantities by 1990. For example, the Lewin report estimated that as much as 7.7 tcf of gas could be produced each year by 1990 at prices up to $4.50 per mcf. However, a large portion of this production would likely be produced from the blanket sands formations where industry has already been active and has amassed a considerable amount of basic geologic and engineering data.

INDUSTRY PERSPECTIVE

Substantial development efforts have been and are underway in several areas. By far, most drilling is in the blanket sands areas where the reservoir distribution is more predictable and the lateral continuity of the gas deposits improves recovery. In addition to the production activities, industry is conducting research without Government assistance in tight sand areas. Cumulative production in tight sand areas through 1975 was at least 12.5 tcf; about 84 percent of this amount was produced from the blanket sands. As shown below, production data from 1974-75 identified over 6,000 producing wells.

1/See footnote on p. 12.

Target formation	Number of producing wells	Annual production (tcf)
Blanket	4,371	.44
Tight lenticular	1,408	.12
Western (lenticular)	373	.06
Shallow	280	.01
Other	174	.11
Total	6,606	.74

DOE estimates current annual production is over 0.85 tcf which is about 4.5 percent of total U.S. gas production.

A common characteristic of the tight sands is their low permeability. This resistance to gas flow is 5 to 2,000 times greater than typical oil and gas producing formations. Also, the gas-bearing formations range from single, relatively thin (10 to 100 feet thick) gas-bearing beds of generally uniform thickness covering large areas to multiple lens-shaped layers of sands interbedded with clays and shales. The varying shapes of the gas-bearing sands and their high resistance to gas flow has made exploration and production from these deposits much more difficult than typical conventional gas deposits.

In order to increase the flow of gas from tight sands deposits, they are fractured, often using hydraulic pressure. Advances in fracturing effectiveness are one key to increasing production from the tight sands. For the lens-shaped deposits it will be important to develop drilling and and fracturing methods which will intersect multiple sand lens layers. In addition, hydraulic fracturing treatments must be designed to prevent wells from clogging with sand or clay which may lie in the well area.

GOVERNMENT ACTIONS TO SPUR DEVELOPMENT

Thus far, the Government has taken two actions to promote further development of this resource. The Western Gas Sands Project has been established within DOE to inventory and characterize the tight sand resources and to test well stimulation methods. Second, prices for the tight sands gas deposits have been increased to about $2.10 per mcf under the Natural Gas Policy Act and could be increased again by FERC. 1/

The Western Gas Sands Project

Through fiscal year 1978 DOE spent $10.2 million on the Western Gas Sands Project, with $7.5 million budgeted for fiscal year 1979 and $8.8 million requested for fiscal year 1980. Project activities include

- --a 5-year resource characterization program being performed by the U.S. Geological Survey for DOE;
- --laboratory research and development; and
- --field projects to test methods of stimulating tight sand gas formations.

The field projects are expected to cost $23.2 million with 8 companies providing $13.6 million of the total. DOE is centering its research and development activities in the three western basins containing lenticular formations.

The objectives of DOE's Western Gas Sands Project have been to

- --define the resource base more accurately,
- --determine the reservoirs' physical and chemical properties,
- --determine appropriate stimulation technology, and
- --assess potential reserves and demonstrate economic productivity to encourage industrial development.

These goals are being revised; DOE is due to publish another research and development plan for the unconventional gas resources in late 1979 or early 1980. Rather than using general goals such as those cited above, we believe the establishment of specific goals is an important part of research program management. (See pages 8 and 9.)

1/FERC's authority to provide higher prices for gas produced from tight sand gas areas is contained in Section 109(b)(2) of the Natural Gas Policy Act.

Prices may be set by FERC

The price of tight sands gas is not decontrolled as is the price of the other three unconventional gas sources. However, FERC has initiated proceedings to consider increasing the allowable price for the tight sand resources to $3.12 per mcf. One issue FERC may resolve in the rulemaking proceedings is the establishment of a method for defining tight sands deposits so they can be distinguished from other types of gas deposits which may be present in the producing areas. The Department of Energy has also requested that FERC key a price ceiling for this resource at the price of imported oil. But, there is no requirement that FERC set separate prices for gas production from tight sands gas deposits.

Other actions to spur development

If FERC does not act to increase the tight sands price ceiling as requested by the Department of Energy, the Administration plans to seek price decontrol for tight sands gas production through an amendment to the Natural Gas Policy Act.

FUTURE PRODUCTION POSSIBILITIES

Future production levels are conditioned by the type of sand deposit, its characteristics, technical developments, gas prices, and in turn, the pace of industry activity. As with the eastern Devonian gas shales, these factors will, in combination, play the major roles in determining the extent these resources will be produced. With the exception of blanket sands, many of which are considered commercial at this time, additional knowledge of the sand's characteristics and geologic structure of the basins will greatly improve the potential for recovery. Such resource knowledge, combined with technical developments which overcome the difficulties of production, can reduce the risks of exploration and production.

With or without dramatic improvements in recovery rates, blanket sand deposits are likely to continue to play an important role in future natural gas production levels. Predictions of gas production from the other tight sand deposits are speculative and dependent on technical advancements and prices which permit higher cost recovery methods to be profitable. The Lewin report 1/ estimated that as much as 7.7 tcf of gas could be produced annually from the tight sands areas by 1990 including production from the blanket sand deposits. Except for the blanket sand areas, technical advancements are needed in order to achieve the estimated production levels.

CONCLUSIONS

The blanket sand areas have been under commercial development by industry for years. For the other types of tight sand deposits, the high resistance to gas flow is a major technical problem which must be overcome by improvements in well fracturing technology. This problem is compounded in the areas with multiple, thin, lens-shaped sands deposits. For these deposits, fracturing technology must be developed to intersect the multiple-sand lenses simultaneously.

FERC has begun proceedings which could result in higher prices for tight sand gas production. If the Commission does not take this action, the Administration plans to ask the Congress to consider legislative action to decontrol prices. Providing additional incentives for gas production should accelerate industry activity in the tight sands gas basins.

1/See footnote on p. 12.

CHAPTER 4

COAL BED METHANE (NATURAL GAS)

Coal beds in the eastern United States contain significant quantities of natural gas, but insufficient information is available to judge the overall quality and potential of methane in western coal beds. Eastern coal beds have produced small but locally important quantities of gas and local use of coal bed gas may increase. Coal bed methane has also caused disasterous coal mine explosions. The coal industry has been primarily interested in the removal of this methane from coal mines as a safety precaution. The gas industry has shown minimal interest in the energy potential of this resource to date.

THE RESOURCE BASE

In the eastern and western coal States considerable quantities of methane are trapped within and adjacent to the coal beds. In the East this resource is located near major population and industrial centers. Little use has been made of this coal gas in the United States, but in some European countries coal bed gas production is common with coal production although the gas is often mixed with air.

Methane in coal was generated naturally during the coal formation process and is trapped within the coal itself, in the natural fractures within the coal, and in the strata adjacent to the coal beds. Because coal is relatively impermeable, any methane which is recovered must generally flow through the natural fractures of the coal. For this reason, coal beds which are highly fractured appear to be the best sources of methane.

The content of methane in coal varies considerably, and limited data have been collected on this subject. Due to lack of data, estimates of the resource size are speculative. However, studies of eastern coals have provided some information. Based on the United States total coal reserves, estimates of coal bed methane resources range from 72 tcf to 860 tcf.

However, much less of the gas than the total resource base is recoverable. Again, estimates of the recoverable quantity are speculative due to the lack of data. Nevertheless, experts agree that some coals contain little recoverable methane and many coal beds are too thin for commercial recovery. Estimates of recoverable coal bed methane range from 2 tcf to 487 tcf.

Limited data on the location and characteristics of some types of coal are part of the information problems. Although resource and geologic data on mineable coal fields in the eastern United States are extensive, practically no data exist for western coal and unmineable coal--coal which is too deep or thin to be mined currently. The importance of such data is evident because unmineable coal, especially in the western States, is assumed to be very plentiful. Also, factors such as the locations of promising sites, the permeability, fracture system, and methane content of coal influence recovery economics.

INDUSTRY PERSPECTIVE

The gas industry has made few attempts to recover coal bed methane; its attention has been focused on more readily exploitable conventional gas deposits. The coal industry has been concerned primarily with diluting methane with air during mining to prevent explosions. Current practice is to ventilate coal mine entries with air to dilute the methane below explosive concentrations and to exhaust it to the atmosphere. Presently, neither industry is planning major efforts to produce coal bed gas.

The gas industry

There are examples of gas industry production of coal bed methane. The Equitable Gas Company of Pittsburgh has been involved in two recovery efforts in the Appalachian area. In 1892, gas flows were detected from the Pittsburgh coal bed during the closing of an old gas well which had been drilled through the coal bed. This well was recompleted to produce the coal bed methane and remained productive until 1968. In the same vicinity an additional 23 wells were drilled into this naturally fractured coal bed before 1950. Through 1974 these wells produced 1.7 billion cubic feet of gas.

The Equitable Gas Company is continuing to develop gas prospects in the Pittsburgh coal bed. The company believes substantial quantities of methane could be recovered from Appalachian area coals. Equitable has gas rights for about 6 percent of the land in several counties under lease which are estimated to contain the equivalent of 10 years' gas supply required by Equitable.

An Equitable official described the company's efforts to obtain coal bed methane. Equitable contacts coal owners, describes the recovery operations, and pays a royalty for any gas recovered. The coal beds currently being tapped are not now being mined, the methane content is high, and no fracture stimulation technology is used when completing the wells. The time required for wells in these areas to recover investment costs is 3.5 to 5.0 years. According to Equitable, the major barrier to widespread production in the East is convincing information which shows coal owners that future mining will not be affected or damaged by gas production from coal beds.

Very little interest in western coal bed methane has been expressed by the gas industry. An official of one company which operates in the western States said that there is almost a complete lack of knowledge of western coal depth, porosity, permeability, and methane content. More information on these factors must be obtained before recovery attempts can be made.

The coal industry

The frequency and severity of coal mine disasters caused by explosions of coal bed methane are well known. These disasters have highlighted the need for methane removal. For many years improving ventilation or slowing the pace of mining were the only methods of reducing methane concentrations in the mines. The current practice of the U.S. coal industry is to increase the rate of mine ventilation. Between 70 to 90 billion cubic feet of methane are annually vented to the atmosphere. Unless the industry begins to capture this methane the amount will increase with the pace of deep coal mining.

In Europe, mining practices now include capture and use of coal bed methane. In this country, the U.S. Bureau of Mines, Department of the Interior, has been developing methods to drain coal beds of methane to reduce coal mining hazards. (See p. 25 for further description of Bureau of Mines methane drainage developments.) These methods can be used to recover the methane for use or sale, but are not yet used widely by the coal industry.

The coal industry's primary interest is the coal itself; its only concern with methane is how fast it can be vented to maintain mine safety. Therefore, it has been considered a nuisance. While noting that the Bureau of Mines methane drainage methods have potential, coal companies are not yet convinced these methods are sound investments. Even so, at least two coal companies are now using the predrainage techniques to vent the gas, and other coal companies are now expressing interest in this resource.

However, the coal industry is concerned about the use of well stimulation technology to extract gas from coal beds.

If stimulating coal beds to increase gas flows also causes unstable mine roof conditions, mining operations become more difficult, costly and may be foregone. Although the Bureau of Mines has successfully applied stimulation methods during several experiments, Consolidation Coal Company cited its own attempt which caused a roof fall adjacent to the well.

The ownership question

Coal companies believe ownership of methane in coal is inseparable from ownership rights to the coal itself. In contrast, the oil and gas industry believes that if gas rights remain with the surface owner then they have the right to produce gas from any formation including the coal beds. A problem obviously arises when the coal rights and the gas rights are held by different individuals. Very few deeds or leases for coal rights mention the methane in the coal, but courts have ruled that coal owners have the legal right to remove gas for safety reasons as part of their access rights to coal.

Complicating the problem are deeds or leases that name coal as a specific substance and then include a general statement about "other minerals." In most States, the meaning of "minerals" includes oil, gas, and petroleum products unless another meaning is specified in the legal document. The definition of minerals as it applies to methane in coal may require clarification.

Several court opinions support the petroleum industry view of ownership, but a pending case in Pennsylvania again raises the issue. A coal owner is attempting to prevent a gas producer with gas rights from drilling into a coal bed. Even though such legal questions could delay development, industry officials believe that these legal questions could be resolved if there were sufficient interest in producing the resource.

GOVERNMENT ACTIONS TO SPUR DEVELOPMENT

The U.S. Bureau of Mines and DOE studies have indicated that the economic feasibility of coal bed methane gas recovery is highly probable. The accumulation of sufficient data to encourage industry participation is a principal goal of Government research. In addition, the price of methane from coal beds will be deregulated under the Natural Gas Policy Act of 1978 (see footnote on page 7), but its potential effect on production is unknown at this time.

The main market for this gas in the future may be limited to on-site space heating or local power generation.

Responsibility for work on methane in coal beds is split between DOE and the Bureau of Mines. DOE is responsible for the methane recovery, capture, and utilization from coal beds which are too deep or thin to be mined. The Bureau of Mines is responsible for mine health and safety research which includes draining methane from coal beds in advance of mine openings. Coordination between the agencies is informal.

Department of Energy

DOE's Methane Conservation, Production and Utilization Project is developing methods and systems for using gas from coal seams which are too deep or thin to be mined. The project's purpose is to promote commercialization of the resource for industry use or for communities close to potential deposits. The project was initiated in fiscal year 1978 with a $2 million appropriation. Funding for fiscal year 1979 was doubled, and $5.0 million is being requested by DOE for fiscal year 1980. About 20 contracts are now funded and contract activities include eight tests of recovery and utilization techniques. Multiple completions in thin coal beds, directional drilling techniques, hydraulic fracturing, and various utilization schemes such as space heating and power generation are being tested.

In addition, the Administration's May 1979 rural development initiatives include a $700,000 grant to the American Public Gas Association to initiate projects to recover gas from coal or shale at six selected communities. The grant, to be administered by DOE, could amount to $3.8 million if the projects are completed.

Should these pilot projects demonstrate that dependable gas supplies can be developed at competitive prices; $300 million in grants, loans and loan guarantees are proposed to be made available for widespread adoption of the proven recovery techniques. Program details are to be developed at a later date and implemented if the demonstrations are successful. Under the initial plans, the Departments of Agriculture and Commerce would administer this program and provide funding through existing legislative authority. The May 1979 White House initiative estimates that 6,500 rural communities with populations of 10,000 or less are potential beneficiaries of such a program.

The U.S. Bureau of Mines Methane Control Research Program

The Bureau's Methane Control Research Program was started in 1964 to develop technology for safe and economic mining of methane-laden coal beds. The technology is aimed at eliminating mine disasters caused by accidental methane ignition during shaft sinking and subsurface excavation. According to the Bureau's 5-year plan, which begins with fiscal year 1979, the expected cumulative funding is $11.5 million.

The Bureau's results to date have been promising and several methods of methane removal have been developed using holes bored vertically into the coal beds from the surface and holes bored horizontally from the bottom of mine shafts and mine entries. These methods are to be applied 3 to 5 years in advance of the mine opening so methane levels can be reduced. The Bureau's methods have been successfully applied in the Pittsburgh coal bed. One of these methods includes hydraulic stimulation to enhance gas flow from the vertical boreholes. As noted on pages 22 and 23, the coal industry remains skeptical as to the safe mineability of coal seams after such stimulation.

The Bureau cites the major benefits from methane drainage as

--reduction of hazards,

--lower ventilation costs,

--reduced mine development costs and increased productivity, and

--small capital investment with the potential to recover investments from gas sales.

In addition, an economic analysis using Bureau methane drainage methods projected that $10 million could be earned from the sale of gas for an additional investment of $2 million.

Even though the Bureau believes its demonstrations are clearly effective, their methods have not yet been widely accepted by the coal industry. Less than one-third of the 2.5 billion cubic feet of gas removed from mines during Bureau-sponsored demonstrations has been sold. The Bureau also points out that effective drainage can be achieved without stimulating coal beds through holes drilled from mine shafts and entries.

Coal seam methane price decontrolled

Sufficient examples upon which to base a reliable portrait of coal bed methane economics have not yet been developed. However, various studies have concluded that methane drained from coal beds in advance of mining, and coal bed methane wells not related to mining operations could be produced at prices ranging up to $3.00 per mcf, depending upon the effort required for recovery. Of course, the costs could be higher or lower, depending on the specifics of each recovery operation.

The decontrol of coal bed methane prices permitted by the Natural Gas Policy Act should result in prices which are sufficient to cover production costs in some areas. 1/ As with shale gas production, the incremental pricing rules could affect industry's interest in producing this resource. However, local users may constitute the initial market for this product and the incremental price rules may not apply in such cases.

Other actions to spur development

Federal efforts could advance the technology and demonstrations needed to show industry that this resource is economically advantageous and answer the uncertainties of fracturing techniques. Also, Federal demonstrations might prove that the use or sale of methane removed from coal beds prior to mining is an economically attractive addition to traditional mining operations.

In addition to decontrol and the research and development activities, additional incentives are proposed for encouraging coal bed methane recovery. As mentioned earlier, the Administration's May 1979 rural development initiatives include a proposal for $300 million in grants, loans, and loan guarantees. These incentives would be made available to rural communities if DOE demonstrations prove the resource can be of local benefit. The President's July 1979 energy initiatives also include a proposed $0.50 per mcf tax credit.

1/See Section 121 of the act (P.L. 95-621).

FUTURE PRODUCTION POSSIBILITIES

Future production from both mineable and unmineable coal beds is dependent on added research and development, but, some recovery methods are now technically feasible and potentially profitable. For these areas, such as coal bed methane drainage in advance of mining, additional demonstrations appear to be necessary if convincing proof of economic feasibility is desired. Before reliable estimates of future production can be made, the feasibility of proposed recovery methods must be tested and the resource characterized. Because of uncertainties in these areas, estimates of future production are highly speculative.

The following areas require further research: resource definition, recovery techniques, and the economics of collecting and marketing the resource. For unmineable coal, the thickness, quality, and locations which will support recovery operations must be identified and demonstrations performed.

According to an official of the Bureau of Mines, methane drainage from coal in advance of mining could contribute 0.5 tcf annually by 1986 and 1 tcf annually by 2000. The Lewin study performed for DOE was not as optimistic; it projected production of 0.05 tcf annually by 1990.

CONCLUSIONS

As the pace of coal mining increases, so will the venting of methane trapped in coal beds. Venting wastes a natural resource at a time when the Nation needs to use its energy resources wisely. Analysis indicates that methane production from both mineable and unmineable coal beds is economically attractive, but demonstrations of recovery methods are necessary for encouraging commercial development. Also, if mineable coal bed methane drainage techniques are used in advance of mining, they should help reduce the risks of coal mine explosions.

Because coal fracturing methods are proposed as a method of encouraging increased gas flows, the fear of mine roof instability is an issue. Due to concerns for miner safety, this issue should be addressed fully if coal companies are expected to place reliance on this drainage technique. Other methods are available for methane drainage from mineable coal so it appears that development of this resource could proceed without use of the fracturing method.

More research and development is required to assess and develop the potential of coal bed methane. Additional information on the applications of current technology, and evidence of economic feasibility from demonstration projects could attract industry or community interest and raise the production from this resource over the next 15 to 20 years. Although production appears to be feasible and economic, there have not yet been enough demonstrations to attract widespread interest.

CHAPTER 5

THE METHANE (NATURAL GAS) OF GEOPRESSURED ZONES

Initial estimates of the total resource base for geopressured zones in Texas and the Louisiana Gulf Coast area have been vast. But, the important question is the amount that can be economically recovered. Some oil and gas industry experts are cautiously optimistic about the potential of this resource while others are skeptical that the energy of geopressured zones can be recovered in any sizeable quantity. Barring unexpected dramatic results from DOE's research and development program, the commercial potential of this resource is not expected to be known before the mid-1980s.

THE RESOURCE BASE

Geopressured aquifers are found in various parts of the world, such as China, the Soviet Union, and the North Sea. One of the largest known geopressured areas lies under the Texas and Louisiana Gulf Coast. These deposits, water bearing reservoirs, occur onshore and offshore at depths ranging from 5,000 to 18,000 feet. They are characterized by abnormally high pressures of 4,000 to 15,000 pounds per square inch and temperatures of 200 degrees to 400 degrees Fahrenheit. 1/

Geopressured zones resulted from compaction of sandy sediments. Water would normally have been forced from these sands due to the buildup of strata above, but these areas were covered with rock which prevented the water from escaping and permitted pressure buildups. As a result of compaction, isolated units of sand and mud under great pressure developed, and methane formed as the sediments were buried in the hot briny waters of these deposits.

Three forms of energy are available from these geopressured zones: (1) the potential energy of fluids under pressure; (2) the heat of the briny waters and; (3) the methane or natural gas dissolved in these waters. Due to the methane content of these geopressured zones, they have been

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1/Normal pressure at these depths in the Gulf Coast region ranges from about 2,325 to 8,370 pounds per square inch. Normal temperature at these depths in the Gulf Coast region ranges from about 70 to 250 degrees Fahrenheit.

classified as an unconventional source of natural gas. However, it may be possible to extract the three energy forms simultaneously. For example, the thermal and kinetic energy could be used through conversion operations for electricity, and the methane could be extracted and sold to pipeline companies.

Estimates of the geopressured resource base show a wide variance but recent studies indicate that the higher estimates may be optimistic.

Type of energy	Size of the resource base 1/
Thermal	44,000 - 176,000 quads
Kinetic	198 - 693 quads
Methane	3,000 - 115,000 quads

These differences are due to differing assumptions about the amount of the resource, the amount of dissolved natural gas per barrel of water, the extent and thickness of the deposits, and the porosity and permeability of the reservoirs. Recent studies have not been optimistic about the size of the recoverable resource, the studies are based on assumptions which can only be verified with field testing. Changes in the assumptions would alter the study results.

One such study was performed for DOE by Louisiana State University 2/ and is based on an analysis of 6,000 wells previously drilled by industry. These wells were drilled in the known geopressured area of onshore Louisiana and those offshore areas under Louisiana jurisdiction. Analysis of the well records showed that about 61 percent, or 3,626, of these wells were geopressured. The study estimated that 34.4 quads of energy are recoverable from this geopressured area including 13.6 tcf of natural gas. These estimates are described in the study as optimistic.

1/Geopressured energy forms are often described in "quads," which means quadrillion Btus. The United States now consumes about 80 quads of energy per year. One quad also is the energy equivalent of 1 tcf of natural gas.

2/"Investigations on the Geopressure Energy Resource of Southern Louisiana," Louisiana State University, Apr. 1977.

Oak Ridge National Laboratory 1/ reviewed and critiqued previous resource estimates. For example, the Louisiana State estimates would increase if the geopressured zones contain free gas in addition to gas-saturated brine. One of DOE's test wells in Louisiana, Edna Delcambre No. 1, indicated that geopressured zones may contain such free gas. In addition, the Oak Ridge study notes that a study of the Texas resource area 2/ emphasized the geothermal aspect of the resource. Due to this emphasis, the Texas study did not include lower temperature aquifiers which could have potential to produce methane alone but have less potential for thermal energy recovery. The Oak Ridge study concludes that until more data are collected, the resource cannot be assessed with confidence.

INDUSTRY PERSPECTIVE

Industry has encountered geopressured reservoirs along the Gulf Coast since 1936, and many thousands of wells have penetrated geopressured zones in the search for conventional oil and gas. The Humble Oil and Refining Company (now Exxon) performed a study over a 10-year period in the 1940s and 1950s and found high concentrations of hydrocarbons in the subsurface waters. The companies with which we discussed this resource were in general agreement that the prospects for commercial development, from industry's perspective, depend on uncertain economics and production risks.

Disagreement was expressed about production conditions, impediments to development, and the technology required for production. For example, one company stated that the methane constitutes the major value of the resource, and that the hot pressured waters were of limited value due to the costs of converting this resource to energy. Another company believes that all three energy sources must be produced in combination for this resource to become a feasible economic prospect.

Others believe that the technology base is adequate and implied that building suitable equipment for producing this

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1/"Geopressure Energy Resource Evaluation," Garland Samuels, Oak Ridge National Laboratory, May 1979.

2/"Frio Sandstone Reservoirs in the Deep Subsurface Along the Texas Gulf Coast--Their Potential for Production of Geopressured Geothermal Energy," D. G. Bebout et al., Bureau of Economic Geology Investigation Report No. 91, University of Texas, Austin, 1978.

resource is a question of redesign. Some thought that the equipment design questions are more serious, particularly if all three resources are to be produced simultaneously. Disagreement was also expressed on production theories, regulatory questions, and environmental concerns.

There is some cautious optimism within industry that this resource could make a major energy contribution. Even among those whose views are optimistic, there is little expectation that this resource will be an important source of energy within the realm of current prices. On this basis industry spokesmen judge the resource too risky a prospect for industry investment today; therefore, they believe the Government research and development program is appropriate for defining the resource potential and demonstrating the economics of production.

GOVERNMENT ACTIONS TO SPUR DEVELOPMENT

The Government has taken action in four major ways to spur the commercial development of this resource. In 1975, DOE initiated a research and development program as part of its overall research on geothermal resources. As part of the Energy Tax Act of 1978 (Public Law 95-618), a tax incentive and a depletion allowance are now provided to stimulate interest in the resource, and the price of methane obtained from geopressured zones is now decontrolled under the Natural Gas Policy Act of 1978. (See footnote on page 7.)

DOE research and development efforts

Three important issues are being addressed by DOE in its research: How much energy is contained in geopressured zones? Where is it located? How can it be developed commercially? Two production methods are being studied by DOE. First, the methane recovery potential of shallow geopressured reservoirs is being assessed. Second, DOE is assessing the potential of deep, high temperature reservoirs for producing methane, electric power, and heat. The research program includes efforts to inventory and characterize the geopressured resources, design and test recovery methods and technology, and study the environmental and institutional problems.

Including the amount budgeted for fiscal year 1979, DOE has spent $56.2 million for geopressured resource activities since 1975. DOE's fiscal year 1979 budget was $27.7 million, and DOE is requesting a budget of $36.0 million for fiscal year 1980. Industry is not yet making large contributions to this program. Program funds have largely been spent for resource characterization and background studies of environmental, institutional, and production difficulties. These studies have also identified prospects for geopressured reservoir confirmation drilling and testing.

DOE is also testing geopressured areas to further the characterization of the resource. The reservoir confirmation program was initiated in 1977 with the test of an oil well drilled through a geopressured area. This abandoned well in Vermilion Parish, Louisiana, produced at rates up to 12,000 barrels of brine per day. Tests are now underway on a second well and several other potential candidate wells have been identified.

Another test in Brazoria County, Texas, which was a widely publicized effort to complete a geopressured well, was not completed. Shale strata collapsed during drilling and the well was abandoned. A second attempt is being made to complete a well near the original Brazoria County, Texas site. As of June 1979, the well had been drilled and preparations were underway to begin the first production tests. If successful, the well will be tested for 2 years. Between fiscal year 1980 and 1984, an additional 20 wells are now planned along with engineering and economic feasibility studies and construction of a pilot powerplant and methane separation facility. Until these activities have produced results, the commercial potential of the resource cannot be assessed with confidence according to DOE officials.

Price and tax incentives

A variety of incentives are now offered for geopressured resource development. The price of gas produced from geopressured deposits is not controlled, and, an investment tax credit for equipment used to extract the resource and a depletion allowance for geopressured wells drilled are available to encourage production. In addition, the Administration proposes that geopressured methane production should receive a $0.50 per mcf tax credit.

Economic incentives address only one aspect of the production question. Technical problems and risks remain and, until more is known about the production of geopressured methane, the economics of production remain speculative. Also, industry officials do not expect commercial production unless DOE's research and development program produces successful results. As a result, providing an incentive such as the tax credit may not result in commercial production at this time.

Other actions to spur development

Based on the uncertainties of this resource, DOE's research and development program will be the key to future production. Based on the current schedule, DOE believes that the commercial potential of the resource will not be known until the mid-1980s. Industry believes that the proper role of Government at the present time is to continue research on this resource because it would not otherwise be accomplished.

FUTURE PRODUCTION POSSIBILITIES

Future production levels will be determined by a variety of factors which are just beginning to be defined and explored in DOE's research program. These factors fall in three general areas including the potential of the resource itself, the cost to extract and convert the resource to useable forms, and the requirement to protect areas which might be developed from environmental damage. Should favorable answers result from the research and lead to commercial interest, ownership issues must be resolved before large-scale energy production can occur. Due to the large number of uncertainties, experts do not expect any large-scale commercial production of geopressured methane before 1990.

Potential of the resource

Efforts to estimate the potential of the geopressured resource have been concentrated on the overall size of the resource base and the characteristics which an individual reservoir must possess to produce the three available sources of energy. Several experts generally agree upon the following minimum characteristics for a potentially commercial geopressured reservoir:

--Temperature should be over 250 degrees Fahrenheit.

--The gas content of the water should be near saturation levels.

--The reservoir must be 300 feet thick and extend for 3 cubic miles.

--The reservoir must produce 40,000 barrels of water per day for 20 years.

Candidate areas for testing have been identified by DOE's research and development program. Previous geologic studies indicate about 3 to 4 percent of Louisiana's subsurface area may contain such economically sized prospects. However, other areas may also prove economic under different production assumptions--particularly if geopressred zones contain more gas than can be dissolved in brine.

<u>Extraction and conversion costs</u>

Once candidate reservoirs have been identified they must be drilled and produced. Since the reservoirs of greatest potential are expected to be found below 7,000 feet, drilling costs will be high. Also, poorly consolidated sand in these reservoirs may cause wells to clog or reduce the flow rates. Industry has a number of well completion techniques to control sand problems, but these have not been tested in wells where the pressures and required production rates are so high.

Also, long-term production must be proven and this will require equipment designed to withstand the corrosive effects of processing the hot brines. While experts believe such technology is available today, the equipment must be designed and tested. High efficiency methane extraction facilities and conversion units must also be designed. The design goal for a methane extraction unit, for example, would be to recover at least 85 percent of the methane in the well waters.

Since geopressured wells would produce great quantities of brine, an acceptable method must be found to dispose of this fluid at reasonable cost. Discharging the brine into the Gulf of Mexico is a possibility if any necessary cooling is performed. Disposal into subsurface aquifers is also possible if the aquifers will accept the large quantities of brine and if the brine does not contaminate fresh water or producible oil and gas reservoirs.

Reinjection of the brines into producing geopressured reservoirs has also been considered as a method of maintaining well pressure. While reinjection is theoretically possible, equipment must be specifically designed to test the reinjection theories. However, some industry officials believe the costs of disposal in this manner may be prohibitive.

Environmental concerns

Besides disposing of hot brines in an environmentally acceptable way, the possibility of surface subsidence is being studied. Subsidence might be caused by compaction of deep sediments as large quantities of pressurized reservoir fluid are produced. The amount of compaction will depend on pressure decline, reservoir thickness, and reservoir compressibility. If compaction occurs across a fault, fault reactivation or a lateral shift in land level may occur in addition to subsidence. DOE plans extensive monitoring to track subsidence activity around its test wells.

The impact of subsidence would vary depending upon the location and use of the land. In areas of low elevation along the coast, the effects of even a small amount of subsidence could be highly destructive. The effects might include flooding of large areas, loss of important animal habitats, and damage to roads and buildings.

There is considerable uncertainty that subsidence will occur or how much may occur with full scale development. Some authorities do not expect any subsidence although they agree the question cannot be answered until actual production occurs. 1/ Those who do not expect subsidence believe that it would not occur with production from great depths where the geopressured zones are sealed with overlying caprock. However, subsidence from natural compaction of sediments in the Gulf of Mexico is a continuing process resulting in flooding of coastal marshes. Additional subsidence from geopressured operations might compound these existing problems.

During the development phase of this resource, the Environmental Protection Agency plans to control discharges through the issuance of permits on a case-by-case basis. It plans to issue periodic guidance on known or expected environmental effects, state-of-the-art control technology, and environmental impact reviews.

1/For example, See "An Analysis of the Potential Use of Geothermal Energy for Power Generation Along the Texas Gulf Coast," John S. Wilson, Burchard P. Shepherd, and Sidney Kaufman of Dow Chemical, USA, October 15, 1975. p. 49.

Legal questions

Although legalities are not now as critical to development as resource characterization and economic feasibility, there are legal questions to be resolved before commercial production can expand. The major questions concern the definition of the resource and ownership rights. Presently, it is uncertain whether geopressured aquifers are legally classified as a mineral, water, or another substance and if extraction rights belong to the surface owner or the mineral owner.

CONCLUSIONS

The potential of geopressured methane is too speculative to depend on as a major contributor to the Nation's energy supplies at this time. Such substantial research and development is required that the commercial potential of the resource is not expected to be known until the mid-1980s. Regardless of whether the recoverable resource may be lower than some of the high initial estimates, the resource continues to merit attention. However, the proposed $0.50 per mcf tax credit may not result in commercial production at this time because the economics of production are speculative and industry believes that research and development is appropriate at this time given the high potential costs and risks associated with production.

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