*U.S. Natural Gas Availability: Gas Supply Through the Year 2000*

February 1985

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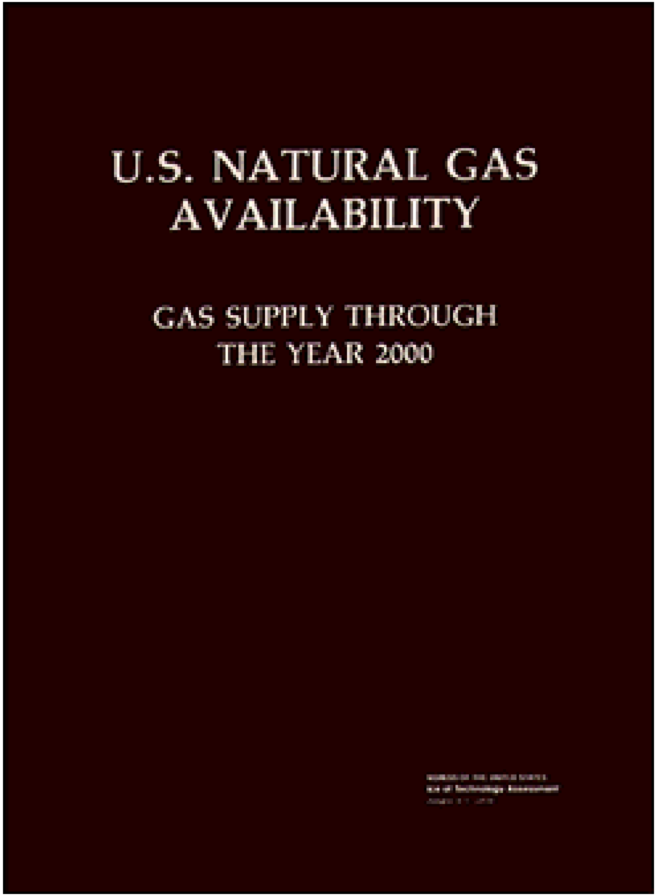

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# Foreword

This report responds to a request from the House Committee on Energy and Commerce and its Subcommittee on Fossil and Synthetic Fuels to conduct a study of the domestic (Lower 48 States onshore and offshore) natural gas availability over the next few decades. OTA was asked to examine both conventional and unconventional sources of natural gas, review current estimates of resource bases and production potentials, and examine key technical issues that will affect the future development of those sources. This request was supported by the Subcommittee on Energy Research and Development of the Senate Committee on Energy and Natural Resources. Two interim reports were released in conjunction with the request: a Technical Memorandum on U.S. *Natural Gas Availability: Conventional Gas Supply Through the Year 2000,* and a Staff Memorandum on *The Effects of Decontrol on 0/d Gas Recovery.* This report combines the results of the earlier reports with considerable additional material on the unconventional gas sources to provide a comprehensive survey of the natural gas sources available to the United States during the next few decades.

National concerns about gas supplies have eased considerably with the current surplus deliverability and recent improvements in the rate of additions to the Nation's proved reserves. The Congress' perception of the Nation's long-term gas supply prospects will still, however, play an important role in its consideration of several important policy initiatives. These initiatives include pressure for repeal of constraints on gas usage embodied in the Powerplant and Industrial Fuel Use Act of 1978, continuing attempts to decontrol natural gas prices, and initiatives to support the added use of natural gas in power generation as part of a strategy to reduce acid rain.

In addition, arguments about the appropriate Federal role in research on unconventional gas sources hinges in large part on Congress' concerns about the need for new sources to supplement the United States' traditional domestic gas sources. OTA hopes that this report will help to clarify the continuing arguments about gas' potential long-term role in future U.S. energy consumption and assist the Congress in formulating effective natural gas and energy policies.

OTA received substantial help from many organizations and individuals during the course of this study. We would like to thank the project's contractors, who prepared critical background analyses, the project's advisory panel and the workshop participants, who provided guidance and extensive critical reviews, and the many additional reviewers who gave their time to ensure the accuracy of this report.

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## INTRODUCTION

The passage of the Powerplant and Industrial Fuel Use Act in 1978, which put legal restraints on future uses of natural gas in the industrial and electric utility sectors, took place in an atmosphere of extreme pessimism about future gas supplies. An Electric Power Research Institute report published a year earlier stated that:

> Today almost every important supply indicator points ominously to the fact that the Nation's ability to meet present and future demands for natural gas may be deteriorating rapidly and will continue to do so unless aggressive and innovative measures to rectify the situation are implemented immediately.[1]

These pessimistic predictions were based partly on short-term problems— periodic curtailments of natural gas deliveries that caused considerable hardship to industry and occasionally even to public facilities and to the commercial sector. They were also based, however, on disturbing long-term trends, such as a declining finding rate for new gasfields and, starting in the late 1960s, the ominous and apparently unstoppable decline of proved gas reserves (fig. 1).

Since 1978, the national perception of future natural gas availability has changed, for several reasons, to one of relative optimism. First, short-term supply is now in a state of surplus; a large gas "bubble," or surplus deliverability, was caused by a combination of energy conservation, recession-induced reductions in industrial activity, and industrial fuel switching from gas to oil as a result of declining oil prices and increased gas prices. At the same time, reserve additions have rebounded from the depressed levels of the 1970s to over 20 trillion cubic feet (TCF) in 1981[2] and over 17 TCF in 1982.[3] Also, the U.S. Geological survey (USGS) and the Potential Gas Committee (PGC) have each recently reaffirmed their earlier estimates of the remaining recoverable resources[4] in the Lower 48 States:[5] the latest USGS estimate implies that about 770 TCF of gas remain as of January 1983, while the PGC estimate implies an even more optimistic 910 TCF.[6] These estimates, which do **not** include gas that could be recovered with completely new technologies and/or substantially higher prices, both exceed the amount of gas that the United States has already produced during the entire history of its gas use. And finally, a series of recent reports by the National Petroleum Council and others[7] have projected that large supplies of "unconventional" gas from tight gas reservoirs, Devonian shales, and coal seams can be made available well within this century.

Along with this new optimism has come some new uncertainty about future gas supply, however. This uncertainty stems from: 1 ) the current

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[1] R. Ciliano, et al., *A Comparative State-of-the-Art Assessment of Gas Supply Modeling,* EPRI report EA-201, February 1977.

[2] Energy Information Administration, US. *Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, 1981* Annual Report, U.S. Department of Energy, August 1982. Because the EIA data series appears to differ somewhat from the earlier American Gas Association data (EIA began in 1977), the interpretation of the recent higher reserve additions is somewhat controversial.

[3] Energy Information Administration, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves,* U.S. Department of Energy, August 1983.

[4] "Resources" and "reserves' are terms that are often—incorrectly—used Interchangeably. The term "reserves" or "proved reserves" refers to the portion of the total gas resource base that has been positively identified by drilling and estimated directly by engineering measurements, and that is recoverable at current prices and technology. "Resources" refer to a broader, more speculative estimate of the total gas remaining to be produced, under conditions defined by the estimator.

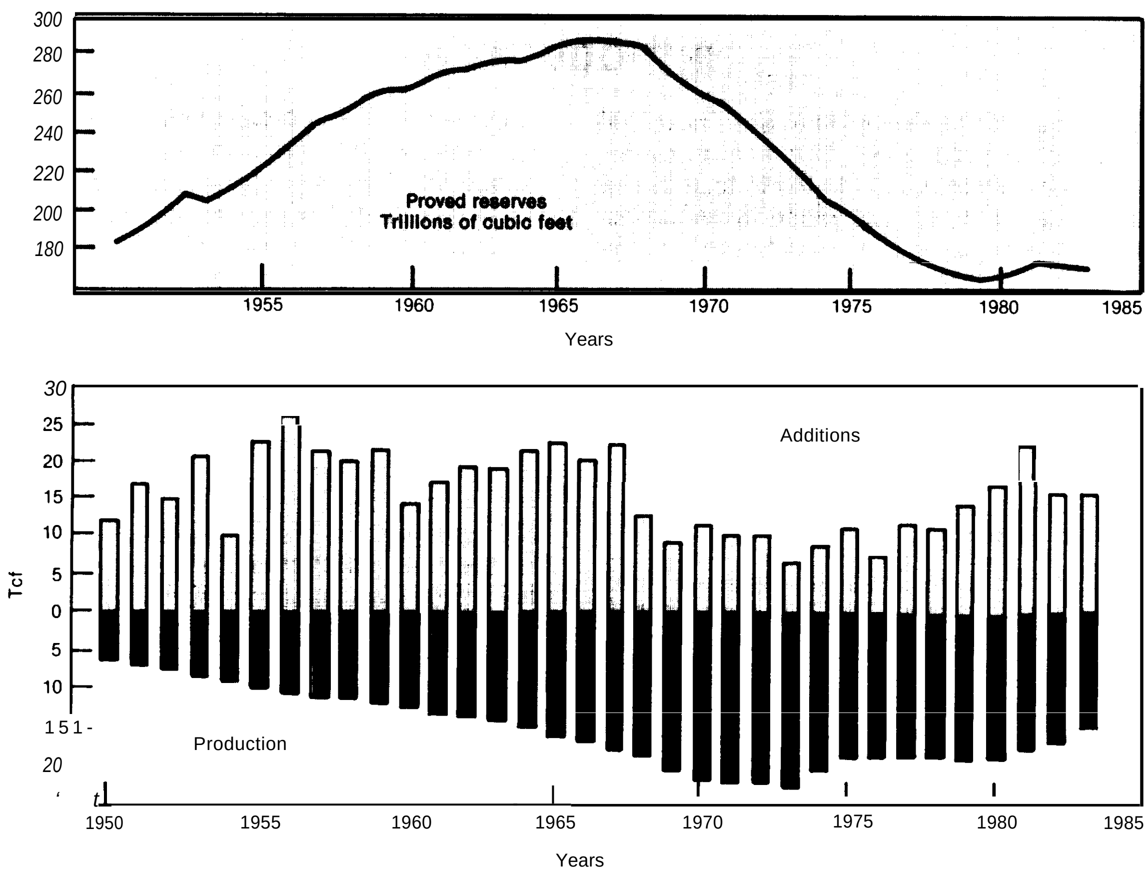
[5] B. M. Miller, et al,, *Geological Estimates of Undiscovered Recoverable Oil and Gas Resources in the United States,* USGS Circular 725, 1975; and Potential Gas Committee, *Potential Supply of Natural Gas in the United States (as of Dec. 31, 1980)* (Potential Gas Agency, Colorado School of Mines, Golden, CO), May 1981.

[6] G. L. Dolton, et al,, *Estimates of Undiscovered Recoverable Conventional Resources of Oil and Gas in the United States,* U.S. Geological Survey Circular 860, 1981; and Potential Gas Committee, *Potential Supply of Natural Gas in the United States (as of Dec. 31, 1982)* (Potential Gas Agency, Colorado School of Mines, Golden, CO), June 1983.

[7] National Petroleum Council, *Unconventional Gas Sources: Volume V: Tight Gas Reservoirs-Parts I and II,* December 1980 and other volumes; R. E. Zielinski and R. D. McIver, *Resource and Exploration Assessment of the Oil and Gas Potential in the Devonian Gas Shales of the Appalachian Basin,* U.S. Department of Energy Report, DOE/DP/0053-1125, undated; and other reports.

**Figure 1.—Natural Gas Production, Additions to Reserves, and Total Reserves of the U.S. Lower 48 States**

(As of December 31)




SOURCE American Gas Association, The Gas Energy Supply Outlook: 1983-2000, October 1983.

low level of proved reserves (which increases the volatility of production); 2) substantial changes in gas prices and demand; 3) rapid advances in technology and the subsequent emergence of new and relatively unproven gas supply regions such as the Western Overthrust Belt; and 4) the potential shift of production from the familiar conventional sources to the less familiar unconventional sources of gas.

In reaction to this changing outlook for U.S. natural gas supply, the House Committee on Energy and Commerce and its Subcommittee on Fossil and Synthetic Fuels, supported by the Subcommittee on Energy Research and Development of the Senate Committee on Energy and Natural Resources, asked OTA to conduct **a study of domestic (Lower 48 States onshore and offshore) natural gas availability over the next few decades.** The study was to examine both conventional and unconventional sources of natural gas, review current estimates of resource bases and production potentials, and examine key technical issues that will affect the future development of those sources.

This report presents the results of OTA's study of U.S. natural gas availability,

[8]The current proved reserves in the Lower 48 States would very quickly be depleted without a constant influx of new reserves. A failure to add substantially to reserves would soon be followed by a major decline in gas production.

# OVERVIEW

There is a distinct possibility that the United States' traditional domestic sources of natural gas, with only modest help from supplemental sources, will be sufficient to maintain present levels of gas usage for the next few decades. In fact, the projection of only moderate rates of decline in production from these traditional sources, barring any collapse of drilling activity, appears to have a growing consensus among gas analysts. OTA concludes, however, that this is not the only plausible future course for U.S. natural gas availability; it is also quite possible that gas supplies from current sources will decline considerably more sharply over the next few decades than predicted by most recent forecasts. In other words, the uncertainty of both the future production and total recoverable resources of natural gas is still high, and the range of plausible gas "futures" is greater than is generally acknowledged. Thus, complacency about U.S. natural gas availability over the next few decades would be an error. **If the United States wants to be confident about the availability of a continued high level of gas supply for the next few decades, it must ensure that it can gain access to significant new sources of supply in case its traditional supply turns downward.**

In addition to "conventional" gas obtainable at current prices with available technology, the United States has substantial gas resources that can come into production only with improved recovery technologies or higher gas prices, or both, This gas resides in tight gas reservoirs, in Devonian shales, in coal seams, and in harder-to-produce conventional-type gas reservoirs. Also, there are substantial possibilities for expanded gas imports. **For each of these alternatives, the magnitude of the recoverable resource base and, for the new sources, the time required to reach high production (or import) levels are difficult to assess. Given the uncertainties about future production, reliance on only one or two of the alternatives might expose the United States to future gas supply shortages. Instead, a** diversified development strategy **that allows for access to all potential gas sources appears most desirable. OTA believes that the probability of obtaining adequate gas supplies is high if such a strategy is pursued.**

## Conventional and Unconventional Gas

**Conventional natural gas is gas that is recoverable using technology that is either currently available or is a modest extension of current technology, at prices similar to or slightly higher than today's.** Virtually all of the resource estimates of "remaining recoverable U.S. gas resources"-including the well-known resource estimate published by the U.S. Geological Survey[9]–are meant to be estimates of conventional gas only.[10] Consequently, OTA's analysis of future conventional gas supplies excludes gas whose recovery depends on new technologies that are not readily foreseeable extensions of existing technologies, or well head prices much higher than today 's. In addition, in order to focus on technical rather than market uncertainties in the supply of conventional gas, the analysis assumes that demand for gas is high enough that exploration and production are not curtailed because of soft markets. Consequently, **"pessimistic" scenarios examined in the analysis of conventional supply reflect only pessimism about technical prospects for gas discovery and production and do not reflect the possibility that low gas demand may drive down exploratory drilling, discovery rates, and production.** Also, the analysis cannot account for any effects that higher gas prices and advancing technology may have on expansion of conventional production into deeper and more hostile waters and other geologically conventional but (currently) uneconomic formations.

**Unconventional gas is produced from *reservoirs that are different in geologic character from conventional gas reservoirs,* and requires higher gas prices or significant advances in production technology—or both—for its economic recovery.** Thus, in examining unconventional gas supplies, OTA has relaxed the price and technology assumptions adopted for evaluating conventional

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[9]G. L. Dolton, et al., Estimates *of Undiscovered Recoverable Conventional Resources of Oil and Gas in the United* States, U.S. Geological Survey Circular 860, 1981.

[10]However, it is certain that these estimates do include some gas that might be characterized as unconventional. Because some production of tight sands gas and gas from Devonian shales has occurred in the past and occurs today, the boundary between "conventional" and "unconventional" is ambiguous.

gas supply. Unconventional gas sources include gas from low-permeability[11] sandstone and limestone formations (so-called "tight gas"), Devonian shales, coal seams, and geopressurized aquifers. Recently, gas vented from deep within the Earth ("deep source gas") and gas hydrates–gas trapped with water in an ice-like state—have been added to the "unconventional" category. (See box A for definitions of the individual unconventional sources.) Of these six unconventional sources, three—tight gas, Devonian shale gas, and coal seam methane—generally are considered to be the most likely to play a significant role in U.S. gas supply within the next 20 to 30 years. OTA has chosen to focus its analysis on these three sources.

[11] Permeability is a measure of how easily liquids and gases flow through porous rock. Thus, low-permeability rock is rock through which liquids and gases may flow only with difficulty.

## Projections of Future Production

**OTA finds that, even if the uncertainties about future gas prices and markets could somehow be eliminated, the technical and geological uncertainties associated with the gas resource base and exploration process are too great to allow a reliable consensus to be established about a single "most likely" estimate of future annual gas production. For the production of *conventional* gas, a credible *range* for Lower 48 State production levels in the year 2000 is 9 trillion to 19 trillion cubic feet per year (TCF), assuming gas demand remains high and gas prices do not soar. This range encom-**

**Box A—The Unconventional Gas Resources**

1. **Tight gas or tight sands gas is natural gas that is found in rock formations of extremely low permeability. It is characterized by slow rates of production, and tight gas wells generally are stimulated to increase flow rates by artificially fracturing the rock around the wellbore. Tight gas formations are found in all gas-producing basins in the United States.**
2. **Devonian shale gas is natural gas found in the fractures and pore spaces and adsorbed (bound) to the physical structure of shales deposited during the Devonian period of geologic time. Devonian shales occur predominantly in the Appalachian, Illinois, and Michigan basins. The natural fractures in the shale provide critical flow pathways for production, but the low permeability of both the shales and the natural fractures generally must be overcome with artificial fracturing or other well stimulation techniques.**
3. **Coalbed methane is natural gas created as part of the coal formation process. It is found predominantly in the form of gas adsorbed to the coal itself, but also as free gas in the pores and fractures of the coal. As with Devonian shale gas, the natural fracture system plays a critical role in production. Also playing a key role is the water often found in the coal seams; the water must be removed before gas can "desorb" from the coal and flow to the well.**
4. **Natural gas from geopressurized aquifers is gas dissolved in brines deep within the Earth under high pressures and temperatures, found primarily in the gulf coast region but also present in the San Joaquin, Piceance, and other basins. In order to produce the gas, the brines are pumped to the surface, the gas removed, and the brines disposed of.**
5. **Gas hydrates are an ice-like mixture of gas and water, called a "clathrate," that forms under certain temperature/pressure conditions often found under water depths greater than 100 ft and under permafrost. The resource is potentially huge and may be augmented by free gas trapped under the impermeable hydrate. At this time, all proposed production methods are highly speculative.**
6. **Deep source gas is natural gas that supposedly has been vented from deep within the Earth and accumulated both as conventional (and the other forms of unconventional) gas and as gas trapped under the "basement" rocks. Its existence—as yet unproven—would imply that large quantities of gas may be found in areas where gas would be unexpected because of a lack of organic-rich sediments. It would also imply that the deep gas resource to be found beneath existing shallow gasfields may be very large.**

**passes drastically different conceptions of the role of conventional natural gas in the United States' future energy supply.** The width of the range reflects uncertainties about the magnitude and character of the remaining conventional resource, the appropriate interpretation and extrapolation of past discovery trends, and the production rates possible from reserves not yet discovered.

**Projections of *unconventional/* gas production suffer from many of the geologic uncertainties associated with projections of the conventional resource, but in a more severe form because there has been less information-gathering and because measurement of geologic parameters generally is more difficult in the unconventional fields.** In addition, these projections are confounded by difficulty in forecasting the rate of development of newly emerging production technologies and by the lack of an extensive production history to provide guidance about the shape of future production. Furthermore, because of the technological risks, the pace of development of the unconventional gas sources will be particularly sensitive to gas prices and to the availability of lower risk prospects for conventional gas production.

In light of these uncertainties, **OTA believes that the year** 2000 **production of unconventional tight gas, over and above production in areas being developed today, could range anywhere from 1 to 4 TCF/yr or perhaps even higher,** depending on gas prices, conventional gas production, the pace of tight gas research programs, and the outcome of numerous geological and technological uncertainties. Similarly, **new Devonian shale production could range from negligible amounts to about 1.0 to 1.5 TCF/yr by the year 2000.** At this time, the technical uncertainties associated with producing coal seam methane are too great to provide a useful estimate of future production from this resource.

In addition to domestic Lower 48 production, the United States can supplement its gas supply with pipeline i reports from Canada and Mexico, and imports of liquefied natural gas (LNG) from a variety of suppliers. Also, there is the possibility of pipeline or LNG deliveries of natural gas from Alaska. OTA has examined available estimates of future pipeline gas imports and Alaskan gas deliveries to the U.S. Lower 48 States; these estimates range from 1 to about 6 TCF/yr by 2000. LNG imports are even less certain, and were not projected. Factors affecting gas imports include the U.S. domestic gas supply balance, gas prices, and the export policies and energy supply situations of the exporting nations.

**The separate projections of conventional gas production, unconventional gas production, and gas imports cannot simply be added together to yield a projection of *total* U.S. natural gas availability,** because the projections have different baseline assumptions and because the projections are not independent—the gas volume attained by any one of the sources affects and is affected by the volume attained by the others. The nature of this interdependence is that neither the "lows' '-the pessimistic estimates–nor the "highs' '-the optimistic estimates–are likely to occur together in the same scenario.

| *Resource* | *Year* 2000 *production, TCF/yr* |
|---|---|
| Conventional gas . . . . . . . . . . | 9-19 |
| Tight gas . . . . . . . . . . . . . . . . . | 1 -4+ |
| **Devonian shale gas . . . . . . . .** | 0-1.5 |
| **Coal** seam methane . . . . . . . . | **unknown** |
| **imports and Alaskan gas . . . .** | **1-6+** |

## The Gas Resource Base

Uncertainties about the magnitude and character of the conventional and unconventional gas resource bases are an important source of uncertainty in projections of future gas production.[12] For **conventional** gas, the critical areas of uncertainty include the:

- role of small gasfields, which up to now have provided an extremely small share of cumulative production and proved reserves;
- potential of deep onshore gas, and gas in frontier areas such as the Eastern and Western Overthrust Belts, the eastern Gulf of Mexico, the Georges Bank, and elsewhere;
- potential for obtaining substantial quantities of additional gas from older gasfields; and
- the possibility of finding large quantities of gas in stratigraphic traps[13] bypassed by old exploration methods:

[12] This is not a trivial statement. It the resource base were sufficiently large, u ncertai nty about the majorit y of its sti ll might not affect projections of near-term production, which presumably will draw from the best-understood portion of the base.

[13] *Stratigraphic traps:* traps, i.e., geologic barriers that ' 'trap' gas and 011 and allow them to accumulate, formed by gradual changes i n the permeability of sedimentary layers rather than by (more easily detected) abrupt structural shifts and deformation of the layers.

In addition, there remain challenging questions about the appropriate interpretation of past trends in gas discovery and their usefulness in projecting remaining discoveries. **Accounting for these uncertainties, OTA concludes that a reasonable range for the remaining conventional gas resource in the U.S. Lower 48 States is 430 to 900 TCF.** Because the definition of "conventional" includes price and technology constraints, however, **this range is conservative; it excludes gas in** deepwater offshore areas, in deep onshore formations, and in small fields that will be added to the economically recoverable resource base by future gas price increases and technological advances.

Three **unconventional** sources are examined in this report. Of the three, **tight gas** generally is considered to have the largest recoverable resource base. Because tight formations often occur in basins that have undergone much conventional gas development, and because considerable development of relatively tight gas has already occurred, there is a substantial base of information from which to project the tight gas resource. The primary areas of remaining uncertainty associated with the tight gas resource base magnitude include:

- the volume of recoverable gas present in the Northern Great Plains and in the numerous tight gas basins that are unexplored or lightly explored;
- the ability of well stimulation technologies to allow production from low-permeability "lenses" (small, discontinuous reservoirs that occur in large, thick formations) that are not penetrated directly by the wellbore (without such "remote" production, much of the tight resource will not be economically recoverable except at extremely high gas prices); and
- our future ability to create very long fractures at low costs.

In addition, the size of the tight gas recoverable resource is quite sensitive to gas prices and to required rates of return. Given the uncertainties associated with all the above factors, **the tight gas recoverable resource will most likely be in the range of 100 to** 400 **TCF.** A more optimistic—but still plausible—view held by some industry scientists would raise the high end of the range by a few hundred TCF.

**Devonian shale gas,** like tight gas, has a considerable history of production, but its development has been more constrained both in area and in technological innovation, and there is less information available for a reliable estimate of recoverable resources. In particular, until recently, resource appraisers did not have the reservoir modeling capabilities that are available to assessors of tight gas resources. primary areas of uncertainty include: basic geological/resource characteristics of areas outside the current limited development area; the potential recovery efficiency available with new stimulation technologies and improved drilling patterns; and the potential for economic recovery from areas that do not have well-developed natural fracture systems. Given these uncertainties, **a moderately conservative range for the Devonian shale recoverable resource is 20 to 50 TCF for the Appalachian Basin,**[15] **with a reasonable potential for up to 80 or 100 TCF with high gas prices and successful technology development. in addition,** there is some potential to add considerably to the recoverable resource if a means is found to produce from the unfractured part of the shale.

**Coal seam methane** has not been extensively developed to date, although there are small development efforts in the Black Warrior Basin in Alabama, the San Juan Basin in New Mexico, and elsewhere. It is the least understood of the three resources, with important uncertainties associated with the basic characteristics of the coal resource, the gas production mechanisms, and the possibilities for and characteristics of new stimulation methods. In addition, access to the gas residing in shallow, minable coal seams is hampered by concerns about ownership of the gas and the possibility that well stimulation (fracturing) will damage the integrity of the rock overlying the coal seam, adversely affecting mine safety. Ex-

[14] Of the several existing estimates of the tight gas resource, only one–the study by the National Petroleum Council—has attempted to estimate the resources in the unexplored/lightly explored basins.

[15] Less is known about the two other Devonian shale basins, the Michigan and Illinois Basins. However, recoverable resources appear likely to be considerably smaller than those in the Appalachian Basin.

isting resource estimates are crude, and although it seems likely that the recoverable resource will be at least a few multiples of 10 TCF, the range of possible resource values probably extends, at least speculatively, up into the 100s of TCF at high gas prices.

| *Resource* | *Recoverable resource, TCF* |
|---|---|
| **Conventional gas** | **430-900+** |
| **Tight gas** | **100-400+** |
| **Devonian shale gas** | **20-100+** |
| **Coal seam methane** | **20-200 +** |

## Natural Gas and Energy Policy

The resource and production estimates have implications for national energy policy. One of the more important is that **any policy that would tend to restrict U.S. gas availability to "conventional" gas supplies—e.g., a policy that restricted gas prices to below market levels and thus discouraged technology development–would strengthen the possibility that natural gas could be in short supply by the 1990s.** This is because the lower end of the range of year **2000** production potential for conventional gas is **9** TCF/yr, far below expected gas requirements. **A willingness to let gas prices seek a market level and an active encouragement of technology development and the exploitation of new gas sources would make it more likely that any shortfall of conventional gas could be made up by alternative gas sources.**

The total recoverable gas resource base will respond to price increases and technology advances in a number of ways. First, as noted above, **the boundaries—and thus the magnitude—of the conventional gas resource base will expand with higher prices and improved technology.** These boundaries are defined by maximum water depth, minimum exploitable field size, maximum feasible drilling depth as a function of field size and geology, minimum "pay" (gas-bearing) thickness, and so on.[16] Not only will formerly uneconomic fields and reservoirs now be developed, but measures will be taken to increase gas recovery from fields and reservoirs whose development would have been less intensive under the old conditions. In fact, because gas prices in some fields have been controlled at below-market rates, gas recovery could be increased merely by allowing gas from these fields to obtain today's free market prices. OTA **calculated the potential increase in recoverable gas from decontrol of the price-controlled fields, over and above increases already programmed into existing legislation, to be 19 to 38 TCF.**[17]

Second, **the magnitude of the unconventional gas recoverable resource base will increase substantially with higher gas prices and advances in recovery technology.** For example, current studies imply that doubling gas prices from today's levels would approximately double the recoverable tight gas resource with present technology. Similarly, solving the numerous remaining technical problems associated with the unconventional resources—improving logging techniques, expanding effective fracture lengths and increasing fracture efficiencies, developing accurate reservoir simulation models, and so on—will allow higher recovery efficiencies and open up more difficult areas to commercial exploitation. (See box B for a list of technical requirements for developing the unconventional gas resources.) With tight gas, which has already seen considerable commercial exploitation and technology development, further technology development still holds the promise of expanding the recoverable resource by 40 percent or more. With Devonian shale gas and coal bed methane, further technology development holds the promise of even larger gains.

Another important conclusion is that, **given the high risks and long leadtimes necessary to establish new sources of supply, the United States should place a high premium on providing an early warning of any impending shifts in gas supply.** Comprehensive data collection and gas supply analysis capabilities exist outside of the Federal Government, for example, in organizations such as the American Gas Association and Gas Research Institute. The perspectives of these organizations and the uses to which they put their forecasts may be quite dissimilar to the perspec-

[16] An ongoing OTA study, *Technology for Developing Offshore Oil and Gas Resources in Hostile Environments,* is examining one of these ' 'bound aries. "

[17] At a market price of $3.50/MCF (1 983 dollars),

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**Box B.—Technical Requirements for Developing Unconventional Gas Resources**

- Improve well measurement technology and interpretive techniques (especially to identify gas-bearing strata, forecast post-stimulation performance, assist in fracture design, and aid "real time" fracture control).
- Increase fracture lengths while improving prediction of fracture direction, containment in proper strata, etc.
- Develop fracturing techniques that can penetrate remote lenses (tight gas).
- Develop "real-time" reservoir and fracture propagation models to allow adjustment of the fracturing process as the fracture is being created.
- Develop new fracturing fluids to prevent "formation damage" (reduction in the flow capability of the reservoir rock due to blocking of pores and other flow passages).
- Develop methods to monitor fracture behavior.
- Improve drilling techniques, especially deviated drilling (primarily coal seam methane, but applicable to Devonian shale and tight gas as well).
- Develop effective dewatering systems (coal seam methane).
- Develop technology to produce from zones with poorly developed natural fracture systems (Devonian shale, coal seam methane).
- Understand the flow mechanisms and geologic features controlling production, develop reservoir models (coal seam methane, Devonian shale, tight gas—in that order, starting with least advanced state-of-the-art).
- Develop exploration techniques to locate fractured zones (especially Devonian shale).

tive and required uses of the Government, however. Consequently, Congress may not wish to rely solely on such organizations for warnings about impending supply problems, Inside the Federal Government, the Energy Information Administration plays the critical role in collecting and analyzing natural gas supply statistics. Maintenance of EIA's capabilities in this area, as well as protection of its independence from the Department of Energy policymaking apparatus should be considered a high priority by those valuing an independent warning system for future supply problems.

## HOW THIS REPORT IS ORGANIZED

The remainder of the report is organized as follows:

- Part I—Conventional Gas Supplies:
  - *Chapter 2: Summary--Availability of Conventional Gas Supplies* summarizes OTA's major findings about future production of conventional gas, the magnitude of the conventional gas resource base, and the potential for gas imports to the Lower 48 States.
  - *Chapter 3: Natural Gas Basics* presents a brief review of basic natural gas terminology and concepts.
  - *Chapter 4: The Conventional Natural Gas Resource Base* reviews resource assessment methodologies, describes and critiques several specific gas resource assessments, evaluates a number of critical resource issues, and presents OTA's conclusions about the magnitude of the remaining resource base.
  - *Chapter 5: Conventional Gas Production Potential* describes four approaches used by OTA to evaluate the gas production potential to the year 2000, and presents OTA's conclusions about this potential.
  - *Chapter 6: Gas imports–Overview* briefly reviews the prospects for gas imports to the Lower 48 States–liquefied gas imports and pipeline imports from Alaska, Canada, and Mexico.
- Part n-Unconventional Gas Supplies:
  - *Chapter 7: Introduction and Summary–Availability of Unconventional Gas Supplies*

briefly defines the unconventional gas resources, describes the definitional problem of separating unconventional from conventional gas, and introduces the major uncertainties in defining the resource base and production potential, then describes the technologies for producing unconventional gas and summarizes OTA's findings about the size of the resource base and the future production potential for this gas.

– *Chapter 8: Tight Gas* describes the tight gas resource and the technology necessary to exploit it, and discusses and evaluates projections of the resource base and future production.
– *Chapter 9: Gas From Devonian Shales* and *Chapter 10: Coalbed Methane* duplicate chapter 8 for these two resources.

# Part I

# Conventional Gas Supplies*

● The material in Part I is based on: ***U.S. Natural Gas Availability: Conventional Gas Supply Through the Year 2000—A Technical Memorandum*** (Washington, DC: U.S. Congress, Office of Technology Assessment, OTA-TM-E-12, September 1983). At the time of publication of the technical memorandum, data on natural gas production and reserves were available through 1981. Currently, data are available through 1983. A portion of the material in Part I has been revised and updated to take account of this new data. However, the two additional years of data generally do not change the conclusions of Part I as originally presented. A small exception is the raising of the lower bound of year 1990 **production potential from** 13 to 14 TCF.

## Chapter 2

# Summary: Availability of Conventional Gas Supplies

# Contents

# Chapter 2

# Summary: Availability of Conventional Gas Supplies

## INTRODUCTION

Within the last 5 years or so, the general perception about the outlook for future U.S. gas supplies has moved from pessimism to considerable optimism. The pessimism was based partly on short-term problems, such as periodic regional shortages, and partly on disturbing long-term trends, such as the declining finding rate for new gasfields and, since the late 1960s, the ominous and apparently unstoppable decline of proved reserves. The new optimism is based on several factors, including the gas "bubble" caused by declining gas demand coupled with high gas deliverability, the rebound of reserve additions to levels which exceeded production in 1978 and 1981, and continuing optimistic estimates of domestic gas resources by the U.S. Geological Survey (USGS) and the industry-based Potential Gas Committee (PGC).

What does this apparent change in the outlook for U.S. natural gas supply mean? Can we now count on natural gas to play a major, perhaps even expanded role in satisfying U.S. energy requirements, or is the seeming turnabout only a temporary respite from a continuing decline in gas reserve levels and, soon to follow, a decline in gas production capabilities?

Part I of this report presents OTA's assessment of the future prospects for the discovery and production of conventional natural gas in the Lower 48 States. This assessment examines the gas resource base and future production potential under the following conditions:

- *wellhead prices* are assumed not to change substantially from today's levels in real terms,
- *new technologies* that are not readily foreseeable extensions of existing technology are not considered, and
- *demand* is assumed to be high enough to avoid reductions in production-potential due to curtailment of investments in exploration and production

Part I also summarizes the prospects for additional conventional supplies to the Lower 48 from pipeline imports from Canada and Mexico, Alaskan gas, liquefied natural gas (LNG) imports, and synthetic gas from coal.

## MAJOR FINDINGS

**Certain technical uncertainties-primarily those associated with incomplete geological understanding, alternative interpretations of past discovery trends, and difficulties in projecting likely patterns of future gas discoveries—are so substantial that by themselves they prevent a reliable estimation of the remaining recoverable gas resource and the likely year** 2000 **production rate.** Even after ignoring the potential for significant changes in gas prices and technology in the future, OTA **could not narrow its range of estimates of resources and future production beyond a factor of 2 from the lowest to the highest estimate.** Inclusion of uncertainties associated with changing gas prices and market demand and the continuing evolution of gas exploration and production technology would undoubtedly widen the range still further.

Specific findings of the study are as follows:

- Current proved reserves in the Lower 48 States will supply only a few trillion cubic feet (TCF) per year of production by the year 2000. All other domestic production must come from gas which has not yet been identified by drilling.
- There is no convincing basis for the common argument that the area of the Lower 48 States is so intensively explored and its geology is so well known that there is a substantial con-

sensus on the magnitude of the gas resource base. Plausible estimates of the amount of remaining conventional natural gas in the Lower 48 States that is recoverable under present and easily foreseeable technological and economic conditions range from 430 to 900 TCF. At the lower end of this range, production in the year 2000 will be seriously constrained by the magnitude of the resource base.

- Assureing market conditions generally favorable to gas exploration and production and no radical changes in technology or gas prices, plausible estimates of the year 2000 production potential of conventional natural gas in the Lower 48 States range from 9 to 19 TCF/yr. In 1990, production is likely to be anywhere from 14 to 20 TCF/yr.
- Because it is unclear whether the recent surge in the rate of additions to proved gas reserves' is sustainable, the range of plausible annual reserve additions is wide even for the near future. The range for the Lower 48 States for 1987 and beyond is from 7 or 8 TCF/yr up to 16 or 17 TCF/yr, assuming that the current excess of gas production capacity ceases and market conditions improve.
- The rate at which gas can be withdrawn from proved reserves, or R/P (reserves-to-production) ratio, may range from 7.0 to 9.5 as a national average by the year 2000, further adding to the difficulty of projecting future production potential.
- An important source of uncertainty in evaluating past discovery trends is the lack of publicly available, unambiguous, disaggregate data about gas discoveries.

[1] The 1981 addition was about 21 TCF v. about 10 TCF/yr or less for 1969-77.

## NATURAL GAS PRODUCTION POTENTIAL

**OTA finds insufficient evidence on which to base either an optimistic or a pessimistic outlook for conventional domestic gas production. Given market conditions generally favorable to gas exploration and production, but assuming that real gas prices do not rise well above today's levels, the production of natural gas from conventional sources within the Lower 48 States could range from 9 to 19 TCF/yr by the year** 2000. Similarly, production in the year 1990 could range from 14 to 20 TCF/yr. Current annual production is about 17 to 18 TCF/yr and actual production ***capacity*** is probably at least 1 or 2 TCF/yr higher. These ranges **do not include gas from pipeline or LNG imports, synthetic gas from coal or other materials, or gas from unconventional sources** that are not producing today. They do include gas from low-permeability reservoirs that is currently economically recoverable, even though this gas is borderline conventional and might be considered unconventional by some assessors.

OTA's wide range for plausible levels of conventional gas production in the Lower 48 States in the year 2000 is in sharp contrast to the relatively ***narrow*** range displayed in publicly available forecasts. Table 1 presents the summarized results of 20 separate forecasts from oil companies, other private institutions and individuals, and Government agencies. A striking feature of this group of forecasts is that 13 of the 15 forecasts that project a year 2000 production level fall within 77 *to* 75 *TCF/yr.* This high level of agreement for a production rate two decades in the future is made all the more unusual by the probability that there are substantive differences in the baseline assumptions used by the various forecasters. The high level of agreement might, however, reflect the probability that the forecasts are not all independent, original estimates; some may simply be averages of other forecasts, reflecting the "conventional wisdom, " and some may have been influenced by others that preceded them.

The wide range in OTA's projection of future gas production reflects the existing high degree of uncertainty about:

1. the magnitude and character of the gas resource base;

**Table 1.—Gas Production Forecasts (In trillion cubic feet)**

| | Oil companies | Other private | Government agencies | Average | OTA |
|---|---|---|---|---|---|
| 1985 | | | | | |
| Lowest | 17.0 | 15,5 | 16.5 | — | — |
| Average | 18.7 | 17.1 | 17.3 | 17.9 | — |
| Highest | 19.5 | 18.3 | 18.0 | — | — |
| 1990 | | | | | |
| Lowest | 13.9 | 13.6 | 14.3 | — | 14 |
| Average | 17.1 | 15.4 | 15.1 | 16.7 | — |
| Highest | 18.8 | 17.7 | 15.5 | — | 20 |
| **2000** | | | | | |
| **Lowest** | **8.9** | **11.6** | **12.8** | — | **9** |
| **Average** | **13.5** | **12.2** | **13.1** | **13.1** | — |
| **Highest** | **14.6** | **13.5** | **13.5** | — | **19** |
| **Number of individual forecasts** | **9** | **6** | **5** | — | — |

NOTE: All forecasts calculate gas on "dry" basis at standard temperature and pressure, Some forecasts include unconventional sources of supply, such as tight sands and Devonian shales; others include only conventional sources.

SOURCE Office of Technology Assessment, based on data in Jensen Associates, Inc., "Understanding Natural Gas Supply in the U.S.," contractor report to the Office of Technology Assessment, April 1983

2. the appropriate interpretation and extrapelation of past trends in natural gas discovery, and;
3. the rapidity with which gas in proved reserves can be produced, expressed as the reserves-to-production ratio.

The first two sources of uncertainty are inseparable; the magnitude and character of the resource base have played–and will continue to play–an important role in shaping trends in gas discovery, and these trends in turn provide important clues to gauging the remaining resource base. Consequently, uncertainties in trend interpretation automatically contribute to uncertainties in resource assessment, and resource uncertainties in turn complicate the process of projecting future discovery trends. Similarly, estimating future R/P ratios will depend on projecting discovery trends and understanding the character of the remaining resources.

Each of the three sources of uncertainty will be discussed in turn.

## Uncertainty 1: The Gas Resource Base

Many individuals and organizations have published assessments of the natural gas resources of the Lower 48 States. Table 2 presents seven such estimates of the gas resources that remained in the Lower 48 at the beginning of 1983. They range from Hubbert's 244 TCF to the PGC's 916 TCF.

**Table 2.—Alternative Estimates of Remaining Conventional Natural Gas Resources[a] in the U.S. Lower 48 States (as of Jan. 1, 1983)**

| Source[b] (publication date) | Trillion cubic feet |
|---|---|
| **Hubbert (1980)** | **244** |
| **RAND Corp. (1981)** | **283** |
| **Bromberg/Hartigan (1975)** | **340** |
| **Shell (1984)** | **525** |
| **Wiorkowsky (1975)** | **663** |
| **US. Geological Survey (1981)** | **774** |
| **Potential Gas Committee (1983)** | **916** |

aThe term "resources" includes proved reserves, expected growth of existing fields, and undiscovered recoverable resources. In all but the Hubbert estimate, the term does not include gas not recoverable by current or readily foreseeable technology nor gas not recoverable at price/cost ratios similar to today 's.

bIn most cases, the sources for these estimates were assessments of either the ultimately recoverable resource or the undiscovered resource base, The estimates shown are derived by subtracting cumulative production from estimates of ultimately recoverable resource or by adding proved reserves and expected growth of known fields to estimates of the undiscovered resource, Where ranges of resource estimates are given by the source, the estimate in this table is based on the mean value,

SOURCE: Office of Technology Assessment, 1983

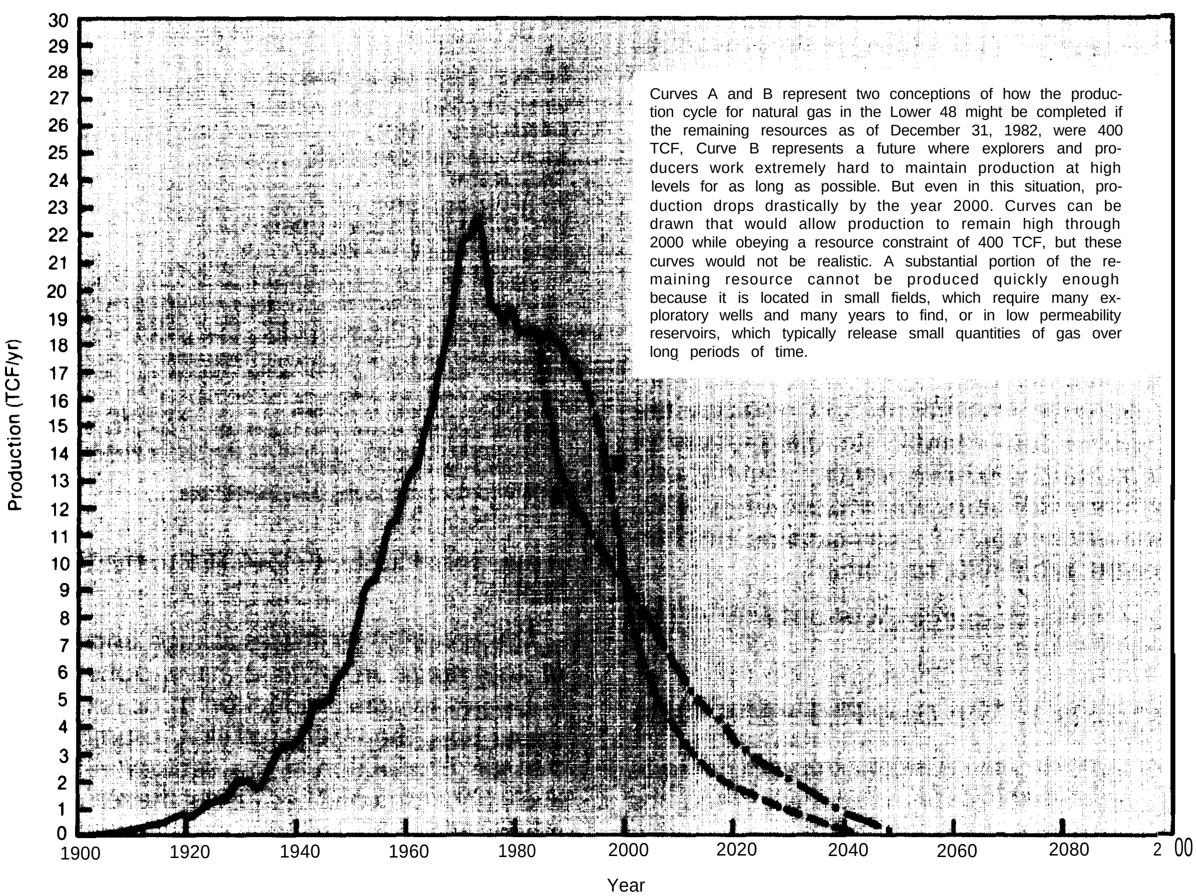
The resource estimates at high and low ends of the range in table 2 have quite different messages for gas production forecasters. At the upper end, the USGS and PGC estimates imply that gas production in this century will be relatively unconstrained because of the resource base magnitude—although this does not rule out the possibility that production may be sharply constrained by the *character* of the remaining resources.[2] In contrast, estimates at the lower end—Hubbert, RAND, and Bromberg/Hartigan—imply a serious resource constraint. If these estimates are correct, gas production will decline substantially by the year 2000 (see fig, 2). Therefore, selection of a "best" resource estimate, or narrowing of the range, could conceivably have profound implications for expectations of future gas production.

Some of the differences in the estimates may merely be the result of differences in baseline assumptions or boundaries. For example, various assessments may use different assumptions about economic conditions and the state of exploration and recovery technology and may have different geographical boundary conditions. They may or may not include areas currently inaccessible to development, gas from portions of tight sands or other "unconventional" sources that are presently recoverable, or nonmethane components of the gas. Finally, assessments may differ in their definitions of the degree of certainty that should be attached to the estimate. Unfortunately, many assessments do not fully specify their assumptions and definitions, nor is it always clear what effects these assumptions have on the resource estimates. Consequently, it is not possible to "normalize" the various estimates so that they are fully comparable.[3]

[2] For example, by their location, depth, degree of contamination, and size distribution of fields and reservoirs.

[3] This does not imply, of course, that some normalization cannot be accomplished. For example, PGC has incorporated into its re-

**Figure 2.-Alternative Concepts of the Natural Gas Production Cycle If Remaining Resources = 400 TCF**
**(conventional gas only)**



It is OTA's opinion, however, that "normalization" of the various estimates would not eliminate the major differences between them. **OTA finds no convincing basis for the common argument that the area of the Lower 48 States is so intensively explored and its geology is so well known that there is a substantial consensus on the magnitude of the gas resource base.**

**Instead, there are several substantive resource base issues that remain unresolved. Among the more important of these are:**

## The Use of Past Discovery Trends

The extrapolation of past trends in the discovery of natural gas has generally led to pessimistic estimates of the magnitude of the gas resource base. For example, of the resource base assessments examined by OTA, three of the four that used trend extrapolation techniques arrived at estimates that were at least 400 TCF below the USGS median estimate. Acceptance of discovery trend extrapolation as a valid method of resource base assessment, therefore, can yield conclusions about the magnitude of the resource base that are radically different from those that result from using other assessment methods.

The validity of using past discovery trends to estimate the magnitude of the resource base depends on whether the trends are affected more by the nature of the resource base than by the general economic and regulatory climate of the times. Resource "optimists" argue that the disappointing trends in gas discovery of the past few decades have resulted from controlled gas prices, high levels of proved reserves, and limited markets that until recently gave little incentive for high-risk or high-cost drilling. They argue that extrapolation of these trends is invalid because the economic and regulatory conditions that created the trends have changed. Resource "pessimists" argue that the trends are driven mainly by a depleting resource base and are affected only minimally by economic and regulatory conditions; therefore, extrapolation is valid.

In addition to this basic issue, other questions have arisen over the validity and interpretation of resource estimates based on extrapolation of past trends. For example, the accuracy of early records of gas discovery and production is questionable; thus, trend analyses cannot accurately incorporate the entire discovery and production history. Also, the precise economic, technological, geographic, and geologic boundaries of these estimates are difficult to define.

## The Potential of Small Fields

Although fields that contain less than 60 billion cubic feet (BCF) of gas have played a minor role in gas production, some analysts believe that small fields will have a major role in the future. The difference between optimistic and pessimistic estimates of the future role of small fields may be 100 TCF or more. In OTA's judgment, the arguments on both sides are based primarily on unproven statistical models of field size distributions and on economic tradeoffs that are highly sensitive to gas prices. Only time and further exploration will settle this issue.

## New Gas From Old Fields

There are sharp disagreements about the extent to which the resources recoverable from older producing fields may respond to price increases. The mechanisms to increase the "ultimately recoverable resources" of these fields might include delaying well abandonments, either by reworking damaged wells or by merely continuing operation to lower abandonment pressures, drilling at smaller spacing to locate gas pockets that otherwise would not be drained, fracturing the reservoir rock to allow recovery from low permeability portions of fields, and expanding development to formerly subeconomic portions of fields. Currently, estimates of the potential increase in recoverable resources range from a few TCF **to** about 50 TCF.

OTA has examined this issue in some detail.[4] We concluded that the potential additional re-

source estimate quantities of presently recoverable gas in tight reservoirs, whereas both RAND and USGS have tended to exclude this gas from their resource estimates. Consequently, equalizing the conventional/unconventional boundaries of the assessments should reduce the differences between PGC's estimate and those of USGS and RAND.

[4]See Office of Technology Assessment, "Staff Memorandum on the Effects of Decontrol on Old Gas Recovery," February 1984.

serves that may be obtained from older fields, if gas in these fields can obtain a market price of $3.50 to $4.50/MMBtu, is about 43 to 65 TCF. Because the NGPA maintains low controlled prices in many older fields, the likely reserve increase with no legislation changes or other new incentives is somewhat lower: 20 to 35 TCF, with some possibility of additional reserves from the current price incentives for "stripper" (low production) wells and production enhancement measures. The above estimates include reserves from delayed abandonment, drilling at smaller spacing (infill drilling), and fracturing and other well stimulation measures, but do not include reserves that might be available from expanding development onto formerly subeconomic portions of fields.

### The Potential of Frontier Areas, Including Deep Gas

Although all resource analysts consider areas such as the deep-water Gulf of Mexico, the deep Anadarko Basin, and the Western Overthrust Belt to have considerable gas potential, considerable disagreement exists over the actual amount of recoverable resources in these areas. Recent indications of engineering problems and rapid pressure declines from deep wells in the Anadarko, coupled with price declines from previous very high levels, raise doubts about whether much of this area's gas resource will be part of the (currently) economically recoverable resource. Some of these doubts must be tempered, however, by recent declines in drilling costs and the continued advance of deep drilling technology and expertise. In the Overthrust Belt, doubts about the magnitude of the resource center on the significance of the failure of explorers to find a giant field over the past 3 to 4 years. Also, areas such as the eastern Gulf of Mexico, the Southeast Georgia Embayment, the Georges Bank, and the Baltimore Canyon have been expensive failures thus far, and their eventual contribution to satisfying U.S. energy requirements is unknown.

Estimates of the recoverable resource potential in the frontier areas vary by up to 100 TCF or more (the USGS and PGC differ by nearly 30 TCF in their assessments of the eastern Gulf of Mexico, alone).

### The Potential of Stratigraphic Traps

Stratigraphic traps are barriers to petroleum migration formed by gradual changes in the permeability of sedimentary layers rather than by abrupt structural shifts and deformation of the layers. Because the structural traps are easier to locate, they have been the primary targets for exploration. Some explorers predict that large resources remain to be found in "mature" areas in subtle stratigraphic traps. Although this issue is not settled, the optimistic argument is weakened by observations that numerous stratigraphic traps *have* been found in the Permian Basin and elsewhere and that the extensive drilling in areas that appear to have good prospects for stratigraphic traps should have uncovered most of the larger traps, which generally are extensive in area. Though it may appear more likely than not that most of the remaining undiscovered traps will be small in volume, a possibility exists that larger fields may have remained hidden because of the less effective exploration methods used in the past and drilling that, while extensive, might have clustered in the wrong places or been too shallow.

In addition to these five issues, a level of uncertainty is ever present in the process of estimating the quantity of a resource that cannot be measured directly prior to its actual **production.** The presence of economically recoverable concentrations of natural gas requires an unbroken chain of events or conditions, the presence or absence of which generally cannot be measured directly. First, adequate amounts of organic material and suitable temperature and pressure conditions for gas formation and preservation must be present. Second, the gas must be free to migrate, and third, an adequate reservoir must be available in the path of migration to contain the gas. Finally, there must be a mechanism to trap the gas, and the trap must remain unbleached until the gas is discovered and produced. These sources of uncertainty account for the various manifestations of risk in natural gas development–the large number of dry holes drilled during exploration, the often huge differences in bids for leases, the multimillion dollar failures of many of the leased areas, **and the continuing disagreements over the size of the remaining resource.**

OTA took into account these general issues, as well as specific problems with individual assessments, in arriving at a plausible range for the amount of remaining gas resources. In OTA's judgment, **a reasonable range for the amount of the remaining conventional natural gas in the U.S. Lower 48 that is recoverable under present and easily foreseeable technological and economic conditions is** 430 **to** 900 **TCF as of December 1982. This range is somewhat narrower than the range displayed in table 2, because OTA considers the low end of the range of resource estimates in the table** to be overly pessimistic. However, the general implication of OTA's range is similar to the implication of the range in the table: **The uncertainty in estimating the remaining recoverable gas resource is too high to determine whether or not the resource base magnitude will constrain gas production in this century.** On the other hand, even the more optimistic resource estimates imply that conventional gas production must decline sharply by the year 2020 or before unless technological advances and/or sharp increases in gas prices add substantial quantities of gas to the "economically recoverable" category.

## Uncertainty 2: Interpretation and Extrapolation of Discovery Trends

The key to projecting gas production potential to the year 2000 is the successful prediction of future discovery trends and of additions to proved reserves. This focus on the discovery process is necessary because gas **that is already discovered, that is, gas in proved reserves, will be of diminishing importance to production as we move into the 1990s.** Assuming a constant R/P ratio of 8.0, the **current proved reserves of about 169 TCF in the Lower 48 will provide only 2 TCF to total production by the year 2000. All other production must come from gas added to proved reserves by the discovery of new fields, the discovery of additional reservoirs in known fields ("new pool discoveries"), the expansion of the areas of known reservoirs ("extensions"), and the reserve changes due to new information or changed economics or technology ("revisions'').**[5]

[5]This last category of reserve additions may be negative.

In addition to the effects of resource base uncertainty, interpretation and extrapolation of discovery trends are hampered by a variety of other problems. These include:

### Inadequate Discovery Indicators

The interpretation and extrapolation of trends for projecting future reserve additions require the availability of discovery "indicator s," such as finding rates for new field wildcats, that can be interpreted in a relatively unambiguous fashion. OTA found that **essentially all indicators available from public data that describe the natural gas discovery process have ambiguous interpretations** because the data are highly aggregated and are dependent on a wide variety of factors. For example, the "exploration" whose success is being measured by a finding rate actually includes several kinds of exploratory drilling, from high-risk, high-return drilling that searches for giant fields in new geologic horizons, to low-risk, low-return drilling that clusters around a new strike or redrills already explored areas that have grown more attractive with price increases. **Because the proportions of different varieties of exploratory drilling may change substantially with changing market conditions, interpreting trends in finding rates and other indicators of exploration success is difficult. This is especially true if the data are highly aggregated geographically.**

### Uncertainty About the Future Growth of New Fields

At least three-quarters of past additions to proved gas reserves have come from the discovery process that *follows* the discovery of new fields. This secondary discovery process seeks new reservoirs in the field and the expansion of known boundaries of already discovered reservoirs. The extent to which recently found fields and future fields will grow in the same manner as fields found in the past is critical to future reserve levels and thus to future production. There has been speculation that the decline in finding giant fields–which require many years and discovery wells to develop fully—and the addition to the reserve base of increasing numbers of very small fields will lead to significant declines in field growth. **If the new fields discovered in the past**

**few years do not grow at near-historic levels, then reserve additions due to new pool discoveries and extensions will decline substantially from recent levels, even if new field discoveries can stay at their present higher rate. OTA believes that such a decline in field growth is plausible, but verification requires additional analysis at the individual field level and continued observation of field growth trends.**

### Difficulties in Interpreting the Recent Surge in Reserve Additions

After the decade 1969-78, during which additions to gas reserves in the Lower 48 States averaged less than 10 TCF/yr,[6] reserve additions have surged to over 20 TCF[7] in 1981 and over 17 TCF in 1982. This surge has been the centerpiece of arguments for future high production levels.

In OTA's judgment, **it is not clear whether or not the recent high rates of additions to proved gas reserves are sustainable, even if drilling rates rebound to the levels achieved before the recent slump.** For example, 13.5 TCF of the total 1981 additions came from secondary discoveries, that is, extensions and new pool discoveries. Normally, such a surge in secondary discoveries would be preceded a few years earlier by an increase in new field discoveries, because recently discovered fields provide the most promising target areas for secondary discoveries. However, the number of new fields discovered in the 5 years before 1981 did not seem high enough to be the primary cause of 1981 high secondary discoveries. Alternative or additional causes of the recent increases in secondary discoveries could include: an acceleration in the normal pace of field growth (e.g., growth that normally might occur over a 20-year period instead is achieved in 5 years, yielding a short-term increase in "per year" reserve additions followed by a dropoff in later years); the rapid development of a limited inventory of low-risk drilling prospects that had been identified in prior years but ignored because of unfavorable economic conditions; and a substantially increased growth potential for the current (and future) inventory of discovered fields because of the expansion of recoverable resources with higher prices and improved exploration and production technology. The first two causes would imply that secondary discoveries will decline sharply in the near future as the limited inventory of prospects is used up; the third cause implies that high levels of secondary discoveries might be sustainable. In fact, it is likely that all three causes played a role in the recent surge, but their relative share is uncertain.

Similarly, it is not clear to what extent recent higher reported rates of new field discoveries are caused by any (or all) of the following factors: an increased willingness of explorers to go after riskier prospects; the exploitation of a limited inventory of low-risk prospects identified by past exploration; an increase in the number of economically viable fields, caused by improved technology and higher prices; and recent changes in reserve reporting methodologies. s

OTA projected a plausible range of future additions to Lower 48 gas reserves by trying to account for uncertainties about the resource base magnitude, the resource characteristics most likely to affect the discovery process, and the actual causes of past and recent discovery trends. OTA concluded that, under the assumed demand /price/technology conditions, **multiyear average levels of total reserve additions could range from 7 to 8 TCF/yr to 16 to 17 TCF/yr or higher by 1987.** Projected average values for individual components of reserve additions are:

| | |
|---|---|
| New field discoveries . . . . . . . . . . . . . . . . . | 1.5-3.5 TCF/yr |
| Extensions and new pool discoveries , . . | 6.0-11.0 TCF/yr |
| Revisions. . . . . . . . . . . . , . . . . . . . . . . . . | 0-+2.0 TCF/yr |

## Uncertainty 3: Production From Proved Reserves-The RIP Ratio

The reserves-to-production (R/P) ratio reflects the rate at which gas is being withdrawn from discovered reservoirs; consequently, it represents the analytical link between projections of new

[6] As reported by the American Gas Association.

[7] As reported by the Energy Information Administration. The American Gas Association, the major source of reserve data prior to 1977, no longer publishes detailed information on reserve additions.

[8] The American Gas Association reported U.S. reserve additions until 1979. The Energy Information Administration began reporting reserve additions in 1977 using a different data collection and analysis procedure, and modified this procedure in 1979.

discoveries and forecasts of gas production. There are very large differences in R/P ratios from field to field, depending on the age, geology, location, and contract terms of the gas production. **OTA projects that the aggregate average R/P ratio for the Lower** 48 **may range from 7.0 to 9.5 by the year** 2000, assuming that economic conditions are generally favorable to production (in other words, in contrast to today's gas "bubble"). The R/P ratio in 1981 was 9.0, the result of a long and relatively steady decline from a level of 30 in 1946.[9]

Although the R/P ratio is sensitive to economic factors, such as actual and expected gas prices and interest rates, technical factors will also play an important role in determining this ratio in the future. Gas in low-permeability reservoirs will play an increasing role in reserves, tending to push up R/P levels. The importance of offshore development will affect national R/P levels because offshore fields have typically been exploited very quickly. As more and more gas is produced in frontier areas with very high drilling costs, difficult tradeoffs will have to be made between the desire for rapid production and the costs of drilling additional development wells. The rate of adding new reserves—which itself is highly uncertain-will determine the average age of the United States' producing fields, an important factor in production rates. Uncertainty in these factors makes it difficult to predict whether future average R/P levels will increase or decrease from today's level.

[9]The recent cutbacks in gas production because of weak demand have temporarily raised R/P even though production capacity has not necessarily fallen.

## Summary of Assumptions and Conditions Underlying OTA's Projections

Table 3 summarizes the assumptions and conditions that lead to the low and high ends of OTA's projection for conventional gas production for the Lower 48 States in the year 2000.

**Table 3.—Bases for OTA's Projections of Natural Gas Production-Baseline Assumptions: Good Market Conditions, Readily Foreseeable Technology**

| **9 TCF/yr in** *2000* | *19* **TCF/yr In 2000** |
|---|---|
| *1. Magnitude of remaining resources:* | |
| *430* TCF | 900 TCF |
| 2. *Character of remaining resources:* | |
| Remaining exploration plays[a] are only of moderate size; few surprises. Some major potential remaining in frontier areas but deep resource is disappointing. Small fields are only a minor source of additional gas because of economics and/or smaller numbers than a straight-line extrapolation would predict. Resource in stratigraphic traps is disappointing; remaining growth of old fields is moderate. | High potential for major new exploration plays. Deep resource is both plentiful and economically accessible. Small fields may play an important role, but many large fields still remain. Resource remaining in mature areas, much of it in subtle stratigraphic traps, is substantial. Remaining growth of old fields is high. |
| 3. ***Causes of* past** *trends in* ***gas discovery:*** | |
| Magnitude and character of the resource base were the primary causes. | Artificially low prices and rigid regulation were as important as the resource base. |
| 4. ***Meaning of recent surge*** in ***reserve additions:*** | |
| A temporary response to higher prices, drilling a backlog of easy but formerly marginal prospects—not sustainable. Possibly also caused by a change in reporting practices. | An indication of a real turnabout in gas discovery; the opening up of major new exploration horizons, readily sustainable if exploratory drilling revives. |
| 5. ***Projected rate of future annual reserve additions:*** | |
| Total: Declines to 7.5 TCF by 1987: | Maintained at 16.5 TCF or above for the next few decades: |
| New field discoveries: 1.5 TCF | 3.5 TCF |
| Extensions and new pool discoveries: 6.0 TCF by 1987 | 11.0 TCF |
| Revisions: O | + 2.0 TCF |
| 6. ***R/P Ratios:*** | |
| ***9.5*** by ***2000,*** predicated on lower permeability reserve additions, difficult production conditions. | ***7.0*** by ***2000,*** predicated on high demand coupled with generally favorable physical conditions. |

aPlay —.An exploratory campaign based on a cohesive geologic idea.

SOURCE Office of Technology Assessment, 1983.

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# OTHER SOURCES OF LOWER 48 SUPPLY

Aside from domestic conventional gas production, gas consumers in the Lower 48 States may have access to other sources of supply, including production from so-called unconventional sources (tight sands, coal beds, gas in geopressurized aquifers, and Devonian shales); pipeline imports from Alaska, Canada, and Mexico; LNG imports from a variety of gas-producing nations throughout the world; and synthetic natural gas from coal and biomass. The potential supply from unconventional sources is discussed in Part II of this report. OTA previously discussed synthetic natural gas in a report released in 1982.[10]

The United States currently imports about 0.8 TCF of gas per year, most of it from Canada. Because each of the four sources of gas import potential have substantial and accessible resources, **imports could theoretically satisfy a major portion of U.S. gas requirements later in this century and beyond. However, each of the import sources, like future domestic production, is subject to considerable uncertainty.** High transportation costs are a particular problem for Alaskan gas and LNG, creating the need, at a minimum, to accept wellhead prices substantially below equivalent oil prices. Similar problems exist for Canadian and Mexican gas. Canadian and Mexican exports to the United States must also compete with the uncertain future requirements of their own domestic gas users. Based on available studies, **the expected import potential from Canada, Alaska, and Mexico may range from 1.0 to 5.7 TCF[11] in the year 2000, with Canada being the most certain large contributor. LNG imports are even less predictable.** Finally, OTA projects synthetic natural gas from coal to range from O to 1.6 TCF/yr by the year 2000.

[10] *Increased Automobile Fuel Efficiency and Synthetic Fuels: Alternatives for Reducing Oil Imports* (Washington, D. C.: U.S. Congress, Office of Technology Assessment, OTA-E-185, September 1982).

[11] This estimate is derived by adding individual estimates for each of the three import categories. This simple addition may overstate the range somewhat because the categories are not independent. For example, high levels of Canadian gas imports might serve to dampen prospects for Alaskan gas, so it is not certain that the "high" Canadian and Alaskan projections are compatible with each other.

# Chapter 3

# Natural Gas Basics

# Contents

# Chapter 3
# Natural Gas Basics

This chapter briefly describes basic theories and terminology used within the report-i. e., it briefly **describes what natural gas is, how it is formed, how it is found and subsequently produced, and** how discoveries are reported. Words in boldface are defined in *Appendix D: Glossary.* **Readers familiar with basic terminology and concepts of natural gas supply may wish to skip this section.**

## WHAT IS NATURAL GAS?

As its name implies, natural gas is a naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in subsurface reservoirs within the Earth's crust. Methane ($CH_4$, a light hydrocarbon, is the primary constituent of natural gas and of principal interest to the energy industry. Associated heavier hydrocarbons such as ethane, propane, and butane and impurities such as water, hydrogen sulfide, and nitrogen occur with the methane. If the concentrations of these other constituents render the gas unmarketable, they must be removed prior to use.

## HOW DOES NATURAL GAS FORM?

There is no universally accepted explanation of how natural gas formed. Most hydrocarbon deposits of significant size have been discovered in **sedimentary basins,** however, and generally are thought to have originated from the decay and alteration of organic matter. Hundreds of millions of years ago, seas that covered a large portion of the land exposed today were inhabited by tiny plants and animals that, upon dying, sank to the bottom and were buried under layers of sediment. In areas of rapid **sedimentation,** organic decay was accompanied by high pressures and temperatures which, over millions of years, effectively "cooked" the organic material into **petroleum (oil and natural gas). Hydrocarbons may** also have been formed by other processes: by the **anaerobic** (without oxygen) digestion of organic materials by bacteria at relatively low temperatures, and inorganically by the chemical transformation of carbon compounds at high pressures and temperatures deep within the Earth. The fraction of natural gas that is bacteria-generated gas, usually called biogenic gas, is at issue, but estimates range to as high as 20 percent or more.[1] As for the "deep earth gas, " a major controversy exists as to whether or not this gas even exists. According to arguments by Thomas Gold and Steven Soter of Cornell University, *most* naturally occurring methane is of inorganic origin and vast reserves remain to be discovered at depths below 15,000 ft.[2]

Temperature and pressure conditions play a critical role in determining the physical state of the hydrocarbons that result. Natural gas may be found at all depths, but it originated mostly in rocks subjected to particularly high temperatures and pressures over long periods of time. It generally is the only hydrocarbon present at depths beyond 16,000 ft. Liquid hydrocarbons occur at shallower depths, from about 2,500 to 16,000 ft,

[1] D. D. Rice and G. E. Claypool, "Generation, Accumulation, and Resource Potential of Biogenic Gas, " *AAPG Bulletin, vol. 65, No. 1,* January 1981.

[2] T. Gold and S. Soter, "Abiogenic Methane and the Origin of Petroleum, " *Energy Exploration and Exploitation* (city, st: Graham & Trotman, Ltd., 1982).

where lower temperatures are characteristic.[3] Most crude oil is found between 6,500 and 9,000 ft, with light hydrocarbon liquids occurring at depths greater than 9,500 ft.[4] Biogenic gas is usually found at depths of a few hundred to a few thousand feet, because it is formed at the low temperatures that accompany shallow burial and rarely is generated at depths greater than 3,000 ft.[5]

[3]H. Douglas Klemme, *Geothermal Gradients, Heat Flow, and Hydrocarbon Recovery. Petroleum and Global Tectonics* (Princeton and Landon: Princeton University Press, 1975), p. 260. Cited in Jensen Associates, Inc., *Understanding Natural Gas Supply in the U. S.,* contractor report to OTA, April 1983.

[4]B. P. Tissot and D. H. Welte, *Petroleum Formation and Occurrence (New* York: Springer-Verlag, 1978), p. 202. Cited in Jensen Associates, Inc., op. cit.

[5]Rice and Claypool, op. cit.

## WHERE IS NATURAL GAS FOUND?

Petroleum accumulations occur as **reservoirs** or **pools—not** in caverns or large holes in a rock mass but in the minute pore spaces between the particles that compose the rock. The greater the amount of pore space in the rock **(porosity),** the larger the quantity of gas or oil that may be contained within it. Pools often occur together in a **field,** and multiple fields in similar geologic environments constitute a **province.**

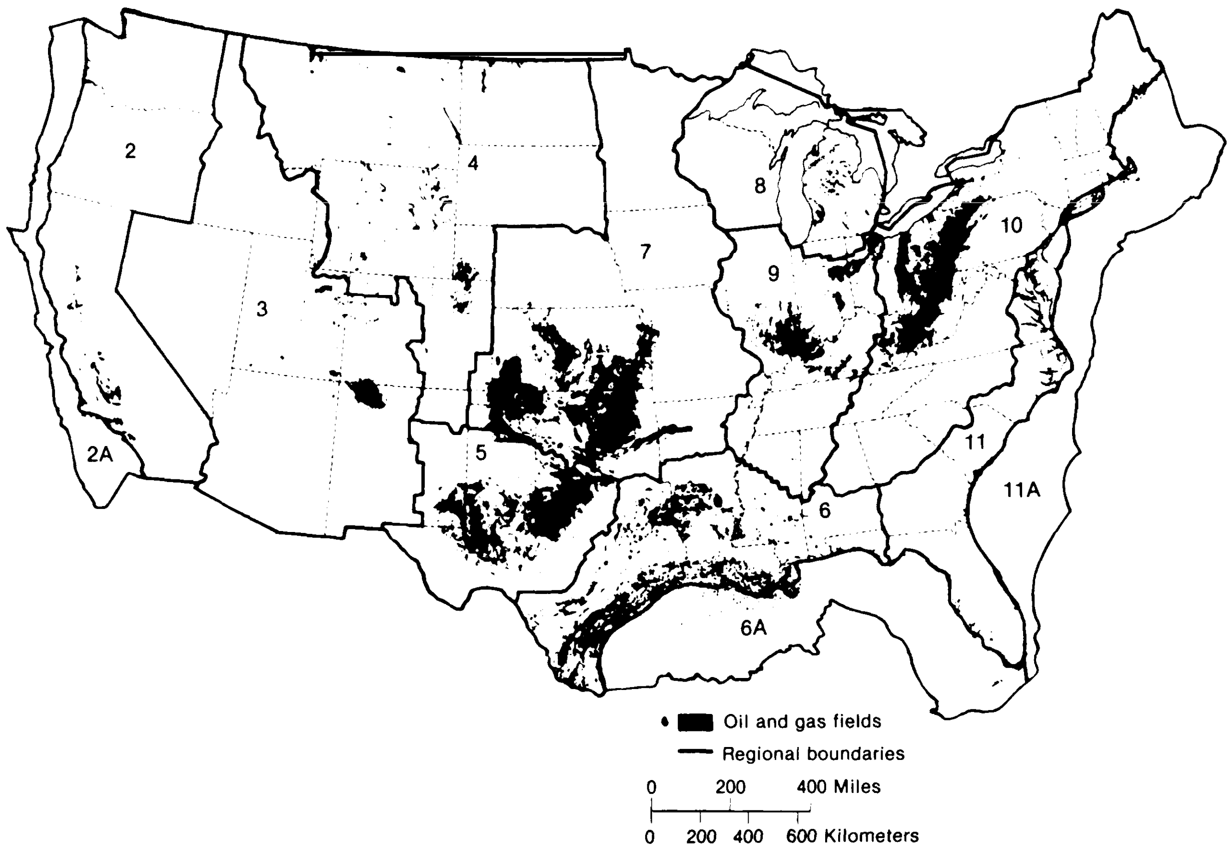
Gas occurs separate from **(nonassociated gas)** and together with oil. When together, it occurs in solution with the oil **(dissolved gas)** or, when no more gas can be held in solution under the pressure and temperature conditions of the reservoir, as free gas **(associated gas)** in a gas cap.

The search for hydrocarbon accumulations is narrowed by the requirement for the presence of organic material in the sediment at the time of burial. Sedimentary basins are the areas most likely to have contained the organic-rich rocks–**source** rocks—required for petroleum formation. Sedimentary rocks compose about 75 percent of the exposed rocks at the surface, but onlys percent of the Earth's crust (outer 10 miles) . The known oil- and gas-bearing areas in the United States are identified in figure 3.

Commercial petroleum accumulations are not usually found in the source rock. Source rocks are generally of too low a permeability, meaning the texture of the source rock does not allow petroleum to flow easily through the pores to a producing well. Typically, after the petroleum has formed, the gases and fluids (oil and **formation water)** migrate from the source bed to a more **permeable** rock, called the **"reservoir rock"** (this process is called "primary migration"). The fluids move in the path of least resistance (or highest permeability) and continue migrating within the reservoir rock (secondary migration) until an impermeable barrier is encountered, which prohibits its further migration into adjacent or overlying rock units or **formations.** The petroleum then migrates further along the barrier to a place of accumulation, called a trap—usually located at the highest point where the reservoir rock contacts the more impermeable, barrier rock. The four requirements for a hydrocarbon accumulation–a source rock, reservoir rock, impermeable barrier rock, and trap–are illustrated pictorially in figure 4.

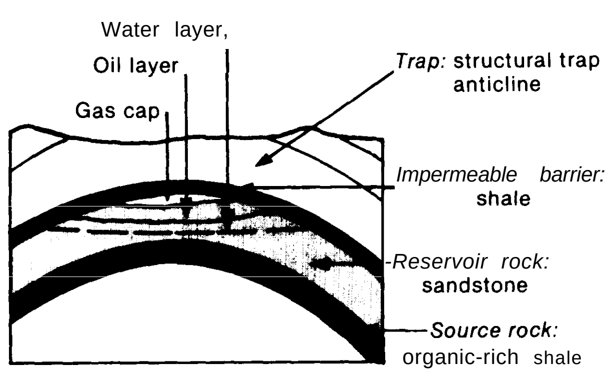
There are three basic types of petroleum traps: **structural, stratigraphic,** and **combination (see** fig. s). Structural traps are formed by earth movements that deform or rupture rock strata, thereby creating favorable locations for hydrocarbons to accumulate. Such structural features as faults and **anticlines** create enclosures that serve as loci for migrating petroleum. Stratigraphic traps are created by permeability and porosity changes characteristic of the alternating rock layers that result from the sedimentation process. In stratigraphic traps, pinched-out beds, sandbars, or reefs serve as reservoirs for migrating petroleum. Combination traps result from both structural and stratigraphic conditions. An example of a combination trap is one that results from a salt dome intrusion during deposition that alters the thickness of the strata deposited.

**Figure 3.—Known Oil- and Gas. Bearing Areas in the Lower 48 States**



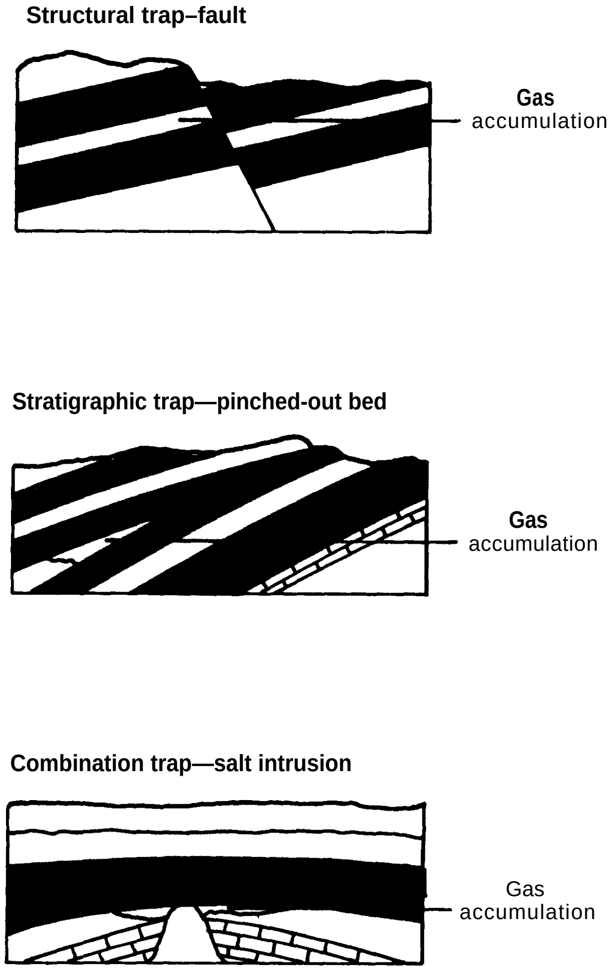

SOURCE: *Estimates of Undiscovered Recoverable Conventional Resources of Oil and Gas in the United States,* U.S. Geological Survey Circular 860, 1981

**Figure 4.—Four Requirements for Petroleum Accumulation**




SOURCE: Office of Technology Assessment

**Figure 5.-Trapping Mechanisms**




SOURCE: Office of Technology Assessment.

## HOW IS NATURAL GAS DISCOVERED?

Before an understanding of subsurface geology was acquired or rules of petroleum occurrence were established, petroleum discoveries were based on surface seeps, knowledge gained from water well drilling, and luck. Today there are a variety of concepts, exploration methods, and instruments available to help geologists locate subsurface hydrocarbon accumulations.

The type of exploration techniques used varies between sites and depends on how much is known about the area being explored. In areas where little is known about the subsurface, reconnaissance techniques—which provide limited information over a large area–are used to identify favorable areas that warrant more detailed investigation. Satellite and high-altitude imagery sometimes reveals large geologic features or trends that are surface expressions of subsurface geologic structure. Magnetic and gravity surveys detect changes in the magnetic or density properties of the Earth's crust and are also used to infer subsurface structure.

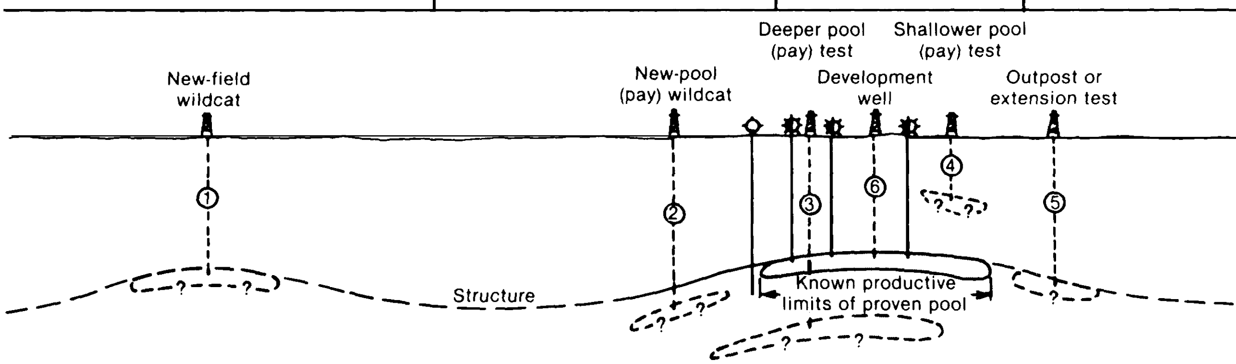
Once a promising area has been identified, more detailed, higher resolution exploratory techniques are used to locate individual prospects for the drill and to project conceptually related groups of prospects, or **plays.** The seismic reflection method, which measures and interprets the reflections of sound waves off of geologic discontinuities, is particularly effective for providing detailed subsurface information. Drilling is the final stage of the exploratory effort and the only sure way to determine if hydrocarbon-filled reservoirs exist in the subsurface.

In some basins, drilling may be performed so cheaply that predrilling exploration expenditures for seismic surveys and other analyses are not justified. These shallow areas are becoming increasingly scarce, and the role of predrilling exploration analysis is increasing in importance, particularly in frontier areas. If these high-cost areas are to be drilled, operators must be relatively sure that the drilling expense is justified.

The degree of risk involved in drilling depends on how much is known about the subsurface at the drill site. As illustrated in figure 6, a classification scheme has been established to categorize the exploratory wells based on their relationship to known petroleum discoveries. There are three basic kinds of exploratory well. A **new field wildcat** is a well drilled in search of a new field, that is, in a geologic structural feature or environment

**Figure 6.—AAPG and API Classification of Wells**

| Objective of drilling | | | | Initial classification when drilling is started | Final classification after completion or abandonment | | | |
|---|---|---|---|---|---|---|---|---|
| | | | | | Successful | | Unsuccessful | |
| Drilling for a new field on a structure or in an environment never before productive | | | | 1. New-field wildcat | New-field discovery wildcat | | Dry new-field wildcat | |
| Drilling for a new pool on a structure or in a geological environment already productive | New pool tests | Drilling outside limits of a proved area of pool | | 2. New-pool (pay) wildcat | New-pool discovery wells *(sometimes extension wells)* | New-pool discovery wildcat | Dry new-pool tests | Dry new-pool wildcat |
| | | Drilling inside limits of proved area of pool | For a new pool above deepest proven pool | 3. Deeper pool (pay) test | | Deeper pool discovery well | | Dry deeper pool test |
| | | | For a new pool below deepest proven pool | 4. Shallower pool (pay) test | | Shallower pool discovery well | | Dry shallower pool test |
| Drilling for long extension of a partly developed pool | | | | 5. Outpost or extension test | Extension well *(sometimes a new-pool discovery well)* | | Dry outpost or dry extension test | |
| Drilling to exploit or develop a hydrocarbon accumulation discovered by previous drilling | | | | 6. Development well | Development well | | Dry development well | |




SOURCE, Lahee classification of wells, as applied by the Committee on Statistics of Drilling of the American Association of Petroleum Geologists, and the American Petroleum Institute Developed by Frederic H Lahee in 1944.

that has never been proven productive. New field wildcats generally have the greatest associated risk because they are drilled based on the least preexisting knowledge. New **pool wildcats–in search** of pools above (shallower), below (deeper), or outside the areal limits of already known pools–are generally less risky because the field in which they are drilled has been proven productive. **Outpost and extension tests are drilled to determine the bounds** of known pools. Development wells are the least risky because their primary function is to extract the petroleum from the already proven pools; they are not exploratory wells.

When an exploratory well encounters petroleum, the quantity of proved reserves is estimated, and the commercial viability of the reservoir evaluated. Proved reserves are determined by analyzing actual production data or the results of conclusive formation tests. The proved area is the area that has been delineated by drilling and the adjoining area not yet drilled but judged as economically producible based upon available geologic and engineering data. Because of its conservative nature, the initial estimate of proved reserves based on a field's discovery well is generally significantly smaller than the quantity of gas ultimately recovered from the field. Wells drilled in subsequent years may increase the proved area of the reservoir or lead to the discovery of additional reservoirs within the field.

Each year, the sum of reserve additions attributed to the three types of exploratory wells are reported by the Energy Information Administration (EIA) as "new field discoveries" (these are the ***initial,*** first year estimates of a new field's proved reserves), "extensions," and "new reservoir (pool) discoveries in old fields. " (In this memorandum, this last category of reserve additions is called new *pool discoveries,* for brevity.) Another reporting category, "revisions," includes those reserves that are added or subracted because of new information about old fields, for example, an indication that the fields will be drawn down to lower pressures because of a gas price increase, pressure histories during production that deviate from the expected values, or the use of measures to increase recovery. Another category, "Net of Corrections and Adjustments," reports reserve changes from corrections of previous arithmetic or clerical errors, adjustments to previously reported gas production volumes, late reporting of reserve additions, and so forth. * Table 4 shows the changes in U.S. gas reserves from 1977 to 1981 as reported by the EIA, *U.S. Crude Oil, Natural Gas and Natural Gas Liquids Reserves–Annual Report.*

***EIA began** its data series in 1977. The American Gas Association and American Petroleum Institute also published reserve statistics in basically the same format (without a "corrections and adjustments" category) from 1966 to 1979, and in a somewhat different format from 1947 to 1965,

**Table 4.–Estimated Total U.S. Proved Reserves of Natural Gas–1977-83**

| Year | Net of corrections & adjustments (1) | Revision increases (2) | Revision decreases (3) | Extensions to old reservoirs (4) | New reservoir discoveries in old fields (5) | New field discoveries (6) | Total discoveries (7) | Production (8) | Proved reserves[b] 12/31 (9) | Net change from prior year (lo) |
|---|---|---|---|---|---|---|---|---|---|---|
| ***Natural gas***[c] | | | | | | | | | | |
| ***1976*** | — | — | — | — | — | | — | — | ***213,278"*** | — |
| ***1977*** | ***–2od*** | **13,691** | **15,296** | **8,129** | **3,301** | **3,173** | **14,603** | **18,843** | **207,413** | **–5,865** |
| **1978** | **2,429** | **14,969** | **15,994** | **9,582** | **4,579** | **3,860** | **18,021** | **18,805** | **208,033** | **620** |
| **1979** | **–2,264** | **16,410** | **16,629** | **8,950** | **2,566** | **3,188** | **14,704** | **19,257** | **200,997** | **– 7,036** |
| **1980** | **1,201** | **16,972** | **15,923** | **9,357** | **2,577** | **2,539** | **14,473** | **18,699** | **199,021** | **– 1,976** |
| **1981** | **1,627** | **16,412** | **13,813** | **10,491** | **2,998** | **3,731** | **17,220** | **18,737** | **201,730** | **2,709** |
| **1982** | **2,378** | **19,795** | **19,340** | **8,349** | **2,687** | **3,419** | **14,455** | **17,506** | **201,512** | **–218** |
| **1983** | **3,090** | **17,602** | **17,617** | **6,909** | **1,574** | **2,965** | **11,448** | **15,788** | **200,247** | **.1,265** |

NOTE: "Old" means discovered in a prior year. "New" means discovered during the report year.
aColumn *4* + Column *5* + Column 6.
*bPrior year* Column *9* + Column 1 + Column 2 – Column 3 + Column 7 – Column 8
cBillion cubic feet, 14,73 psia, 60° F.
dConsists only of reported corrections.
eBased on following year data only.

SOURCE' Energy Information Administration, US. *Crude Oil, Natural Gas, and Natural Gas Liquids Reserves-1983 Annual Report,* DOE/EIA-0216 (83), October 1984.

# HOW IS NATURAL GAS PRODUCED?

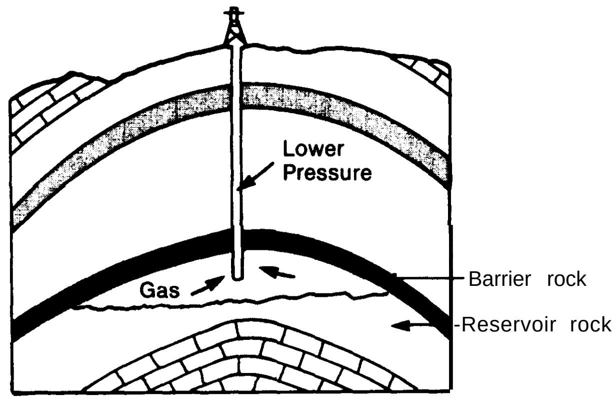
The way in which gas is produced depends on the properties of the reservoir rock and whether the gas occurs by itself or in association with oil. As illustrated in figure 7, hydrocarbons in the reservoir rock migrate to the producing well because of the pressure differential between the reservoir and the well. How readily this migration occurs is a function of the pressure of the reservoir and the permeability of the reservoir rock. When the reservoir rock is of low permeability, the rock may be artificially fractured to form pathways to the well bore. This is accomplished either with explosives or by hydraulic means, pumping a fluid under pressure into the well.

Production can continue as long as there is adequate pressure in the reservoir to propel the hydrocarbons toward the producing well. * If gas is the only propellant, the reservoir pressure decreases as the gas is extracted and is eventually no longer sufficient to force the hydrocarbons toward the well. In a water-drive reservoir, water displaces the hydrocarbons from the pores of the reservoir rock, maintaining reservoir pressure during production and improving the recoverability of the hydrocarbons. In most reservoirs, gas recovery is high, generally greater than oil recovery. A "typical" recovery value of 80 percent is often cited, but the basis for this value is not firm, and **recovery is certainly** less in many reservoirs u rider current conditions. When gas occurs in association with oil, it can be reinfected into the reservoir to maintain pressure for maximum oil recovery. Gas is also reinfected when there are no pipeline facilities available to transport it to market.

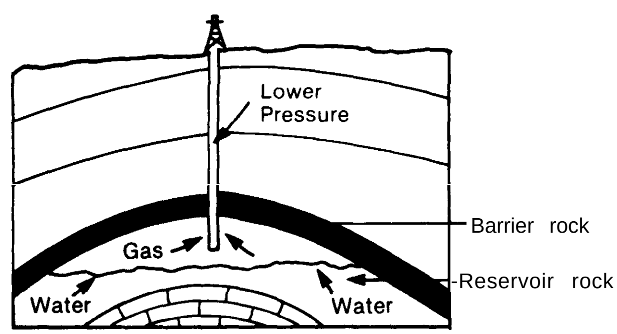
Once the raw gas is produced from the well, it is gathered with production from other nearby wells and processed to remove natural gas liquids and impurities that could cause problems in the pipeline. The gas is then sent by pipeline to local gas utilities who sell it to the end-user. In some instances, such as those involving large industrial users, the pipeline will sell directly to the end-user and bypass the local gas utility.

**Figure 7.— Production Mechanics**

**Gas drive mechanism**




**Gas and water drive mechanism**




SOURCE Off Ice of Technology Assessment

*However, the requirement that the revenues generated by gas sales at least match the expense of operating the well generally WIII force an end to production before the flow of gas actually ceases.

Chapter 4

# The Natural Gas Resource Base

# Contents

# Chapter 4
# The Natural Gas Resource Base

> About the only thing that any estimator can say with certainty about his (resource) estimate is that it is wrong.
>
> Richard P. Sheldon
> U.S. Geological Survey

The focus of this report is on U.S. natural gas availability for the next few decades—and, specifically, on the gas supply that can be provided by production in the Lower 48 States. Some analysts have claimed that the resource base is not an important constraint to gas supply during this period because the U.S. Geological Survey (USGS) estimated resource represents over 40 years of supply at current production levels, which does not count huge resources of unconventional gas (e. g., tight sands gas and methane from geopressurized aquifers) and potential imports of liquefied natural gas (LNG) or pipeline gas from Mexico, Alaska, and Canada.

In OTA's opinion, the claim that the resource base is unimportant to "midterm" (1 ***985-2000)*** supply is arguable. Most theories of resource depletion imply that the "easiest" part of the resource base—for gas, this would be the largest, most accessible fields—tends to be discovered and exploited in the early stages of development and that declines in discovery rates and production will occur well before the "last" resources are discovered and extracted. Consequently, the resource estimates of USGS and the even higher estimates of the Potential Gas Committee (PGC) do **not** necessarily imply a capability to continue gas production at current levels for decades to come. These estimates indicate that we have already produced about 40 percent of the Lower 48 gas resource obtainable within the current price technology regime. The remaining 60 percent will be more difficult and more expensive to find and eventually extract than the already produced portion. The very pessimistic recent estimates of M. King Hubbert[1] imply that the United States may have produced 70 percent of all the gas it shall **ever** produce in the Lower 48. The I--lubber-t estimate thus implies that the United States may encounter an almost immediate drop-off in discoveries and reserve additions, followed shortly thereafter by sharp reductions in gas production. Even the more optimistic USGS and PGC estimates do not deny the possibility of significant reductions in supply within this century. * Therefore, an understanding of resource base estimates is important to midterm as well as long-term planning regarding natural gas policy.

In this section, OTA has not attempted to create a new, independent assessment of U.S. natural gas resources nor to settle on any existing assessment as the "best. " Instead we attempted to accomplish the following four goals:

1. To give the reader an idea of how natural gas resource assessments are made.
2. To describe the problems associated with general resource assessment methods and with particular individual assessments.
3. To define the continuing areas of controversy about the size and characteristics of the remaining conventional gas resource base.
4. To convey OTA's evaluation of these controversies and of the credibility of some of the most widely used assessments.

[1] M. K. Hubbert, "Techniques of Prediction as Applied to the Production of Oil and Gas, " in *Oil and Gas Supply Modeling,* S. *1.* Gass (cd.), National Bureau of Standards Special Publication 631, May 1982.

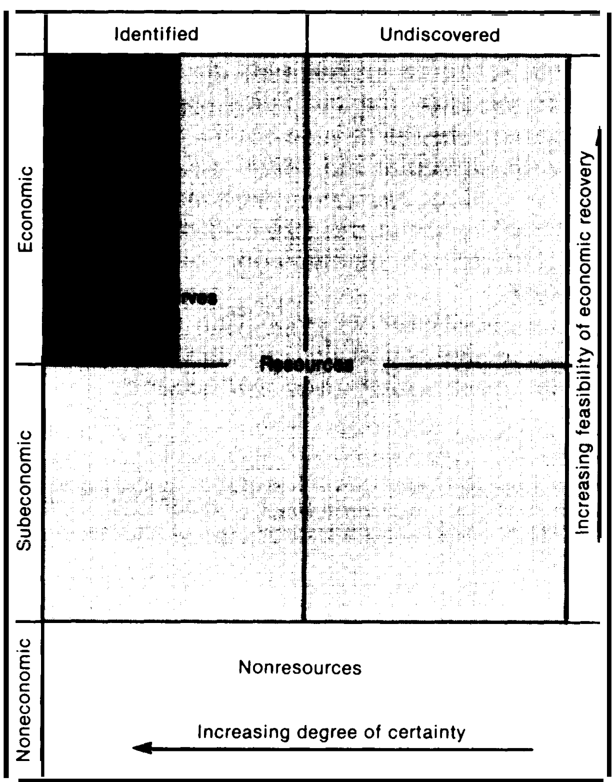
* For a discussion about the production implications of the Hubbert, USGS, and PGC assessments, see ch. 5, "Approach Number 4–Graphing the Complete Product Ion Cycle. "

# RESOURCE BASE CONCEPTS

An important source of difficulty in interpreting and comparing resource base estimates is the failure of the estimator to state and explain precisely the boundaries of his estimate—his definition of the resource base—and the failure of the client to comprehend what a resource base is, or what a **particular resource base is.**

The well-known McKelvey Box (named after its originator, the former director of USGS) is a useful tool in explaining basic resource base concepts (see fig. 8). The McKelvey Box classifies resources according to their economic feasibility of recovery and the geologic certainty of their occurrence. The outer boundaries of the box define the total amount of the material–in this case, natural gas—remaining within the crust of the Earth. The top third of the box (the proportions are **not** meant to be indicative of magnitude) represents gas that is economically producible at current prices using existing technology. The middle third represents gas that is expected at some **future time to be producible but is currently not economically producible, either because of the absence of recovery technology or because of economic conditions.** The lower third represents gas accumulations under such difficult physical conditions that they are likely never to be economically producible. obviously, our inability to accurately project future economic conditions and future technology developments prevents us from knowing where to place the line between subeconomic resources and "nonresources. "

**Figure 8.—The McKelvey Box**




SOURCE: Adapted from V. E. McKelvey, "Mineral Resource Estimates and Public policy," *American Scientist,* vol, 60, No. 1, 1972, pp. 32-40.

The left half of the box represents identified resources— "resources whose location and quantity are known or are estimated from specific geologic evidence. The economically recoverable portion of the identified resources is called "reserves" in the box, but this is not a universally accepted definition. (However, it is generally accepted that use of the term "reserves" to designate the total recoverable resource is a poor usage of the term. Reserves should always refer to gas that is in some sense within the ready inventory available for production. ) **Proved or measured reserves are the most certain portion of the recoverable identified resource, gas which has been estimated from** geologic evidence **supported directly by engineering measurements.** An actual physical discovery by drilling is necessary for inclusion within this category. The remainder of the recoverable identified resource is somewhat poorly defined because of disagreement about what "identified" or "discovered" means. To USGS, for example, untapped reservoirs in discovered fields belong to the "discovered" resource,[3] whereas to the PGC, they are "undiscovered. '

[2] G. L. Dolton, *et* al., Estimates *of Undiscovered Recoverable Conventional Resources of Oil and Gas* in *the United* States, U.S. Geological Survey Circular 860, 1981.

[3] Ibid.

[4] Potential Gas Agency, *Potential Supply of Natural Gas in the United States (as of Dec. 31, 1980),* May 1981.

A critical feature of the components of the resource base is that they are not static. As the production and discovery process continues, gas flows out of reserves and is processed, distributed, and consumed, and other gas moves from "undiscovered" to "identified" as geologic knowledge increases. Additionally, improved technology and economics cause gas to move from the subeconomic to the economic portion of the resource base. For example, improvements in offshore drilling technology may allow drilling in deeper waters and more hostile conditions, opening up new territories to development. Higher gas prices may allow the development of smaller reservoirs that were previously uneconomic, or allow known economic reservoirs to be developed more intensively and drained to lower abandonment pressures.

In the history of development of nonrenewable resources, the process of advancing technology and knowledge and of changing economic conditions has not always been smooth. Consequently, assessments of nonrenewable resources have tended to run in cycles. The discovery of resources in areas or under geologic conditions where they had not been expected or the development of new extraction and processing technologies can generate higher estimates of the remaining resource which may then taper off as that portion of the resource base is systematically depleted. For most resources, analysts assessing the remaining recoverable materials at the end of each cycle have been convinced that the most recent cycle upturn was the last and that resource depletion was imminent. They have been proven wrong time and again. *

Recognizing this, many resource estimators have confined their assessments to only a portion of the McKelvey Box, usually the top third and a small portion of the middle, subeconomic third. In doing so, they explicitly accept the possibility that changing economic and technological conditions could make their recoverable resource estimates obsolete. Unfortunately, the stated boundaries of the assessments are seldom very precise, and it is not always clear that the estimators have consistently followed their own specified rules for including and excluding portions of the total physical resource. Furthermore, besides the ambiguity of the boundary definitions, some resource assessments have chosen different boundaries than the "top third and a small portion" indicated above. Hubbert, for example, claims to capture the **ultimately recoverable resource—the top two-thirds of the box—in his estimate, although he restricts the estimate to "conventional" gas and** excludes such sources as methane in coal seams. s

The differences in economic/technological boundary conditions between alternative gas resource assessments is one of several reasons why comparisons of assessments must be handled with caution. Table 5 lists some of the common problems encountered in comparing estimates.

*Oil has undergone such cycles of apparent depletion followed by large new discoveries and drastic upward revisions in resource estimates. Two other well-known materials that have undergone similar cycles are uranium and iron ore.

'Hubbert, op. cit.

**Table 5.—Why It Is Difficult to Compare Resource Estimates**

- Geographical areas (or geological limitations, such as depth) included in the estimate may be different—especially offshore boundaries.
- Assumptions about economic conditions and the state of technology may be different. Also, these assumptions are often poorly defined and appear in some cases to have been applied inconsistently.
- Some estimates may have included some unconventional resources.
- Areas that are currently legally inaccessible (e.g., wilderness areas) may or may not be included.
- Definitions of "undiscovered" may differ; they may or may not include undiscovered reservoirs in known fields.
- Degree of optimism about estimates (e.g., assigned probabilities) may differ.
- Estimates may or may not correct for liquid content and for impurities.

SOURCE: Office of Technology Assessment, 1983.

# APPROACHES TO GAS RESOURCE ESTIMATION*

Although the extensive literature on oil and gas resource assessment identifies a wide variety of estimation techniques, all of the techniques fall into two basic categories. Geologic approaches rely on information and assumptions about the physical nature of the resource: volumes of sedimentary rock, numbers of geologic structures, presence of "source" rocks, time profiles of subsurface pressure and temperature, and the like. Historical approaches rely on the evaluation and extrapolation of past trends in gas production and discovery in the assumption that the size and character of the resource base, rather than transitory economic conditions and technological developments, are the most important factors controlling the discovery and production cycle. If this assumption is correct, the evidence provided by the manner in which the development cycle has unfolded can be used to ascertain the nature of the resource base.

## Geologic Approaches

Geologic approaches run the gamut from simple–for example, the collection of expert geologic opinion on the size of the overall resource base–to complex procedures involving probabilistic estimates of the geochemical and geologic factors affecting the formation, migration, and accumulation of gas. The methods listed may be used in combination.

in **geologic analogy, untested areas are examined** for comparison with known producing areas. Comparisons range from simple evaluations of hydrocarbon source beds or reservoir beds to evaluation of dozens of factors. Because the use of analogy is basic to all geologic and geochemical understanding, this method in some sense is the basis for all the other methods.

In the **Delphi approach, in its simplest form, each member** of a group of geologists evaluates the geologic evidence available for an area and estimates the area's potential resources. These individual estimates are then reviewed by the group, possibly modified, and then averaged into a single estimate. This approach may also be used as a tool to assist other resource estimation approaches, as when experts are asked to jointly evaluate the hydrocarbon yield of an untested area in barrels per acre-foot as an input to a resource assessment using a volumetric yield approach (see below).

**Areal-yield and volumetric-yield approaches involve the estimation of the amounts of hydrocarbon** per unit area or volume of potentially productive rock in a region and the multiplication of these estimated yields by the appropriate area or volume. The yields are generally calculated by geologic analogy.

**Geochemical material balances, elaborations of the volumetric-yield approach, attempt to account explicitly for** the process of gas generation, migration, and entrapment. Rather than estimating a simple volumetric yield, for example, this approach might estimate the amount of organic matter in source beds, the fraction converted into hydrocarbons, the fraction actually able to move from the source beds into reservoirs, and finally the fraction of this amount actually trapped and concentrated and thus available for extraction.

**Field number and size approaches attempt to count or estimate the number of prospective fields in the area being evaluated and to estimate their success rate and size distribution in order to yield an overall area resource estimate.** Estimation methods include actual counting of structural traps by using seismic surveys, extrapolation from historic field size distributions (a historic approach, as discussed below), and calculation of success ratios by geologic analogy. Other levels of aggregation besides the field are also used; play analyses, for example, focus on groups of fields or prospects with several common geologic characteristics.

Some generalizations can be made about these approaches. The simple methods that use few factors to calculate gas resources all share the risk that key geologic factors, such as the temperature

*This section is based largely on U.S. Geological Survey Circular 860, "Estimates of Undiscovered Recoverable Conventional Resources of Oil and Gas in the United States, " G. L. Dolton, et al., 1981; and D. A. White and H. M. Gehman, "Methods of Estimating Oil and Gas Resources, " AAPG Bulletin, vol. 63, No. 12, December 1979.

history of the rocks, may be left out. The converse is that the more complex methods, such as geochemical material balances, may assume a higher level of geologic knowledge than currently exists. Although the breakdown of the resource assessment into several individual components appears precise, the uncertainty associated with each component is quite large and the potential for error in the resource estimate is high. For example, incorporating factors such as pressure and temperature histories into resource estimation allows the estimator to account directly for the probability that petroleum actually was formed and survived. However, because the geology of most areas has changed significantly over time, it is difficult to trace these changes to reconstruct the temperature and pressures that existed during the periods of hydrocarbon formation, migration, and accumulation.

The simpler methods are most useful in the early stages of development of a basin when few data are available and the r-teed for expert judgment and intuition is at a peak. The obvious disadvantage, however, is that documentation of the estimation process is minimal or, in the case of the simplest Delphi approach, lacking entirely. The credibility of these estimates, then, rests mainly on the reputation of the experts involved in the assessment or of the sponsoring organization.

Finally, the geographically disaggregated approaches, such as play analysis, are most useful when considerable exploration data are available. Many analysts think highly of these approaches, perhaps because the approaches deal in units that most accurately reflect the discovery process and thus allow participants in the resource assessment to draw most readily on their experience for geological analogs.

## Historical Approaches

A variety of historical approaches to resource estimation rely on extrapolation of historical trends in production, reserve additions, and discovery rates as functions of time, number of wells drilled, or cumulative feet of exploratory drilling. Some of these approaches lack explicit assumptions about geology and simply search for curves that achieve the best fit to the data. Others (e. g., some of Hubbert's approaches) first assume general models of the production and discovery process and then adjust the models to fit the data.

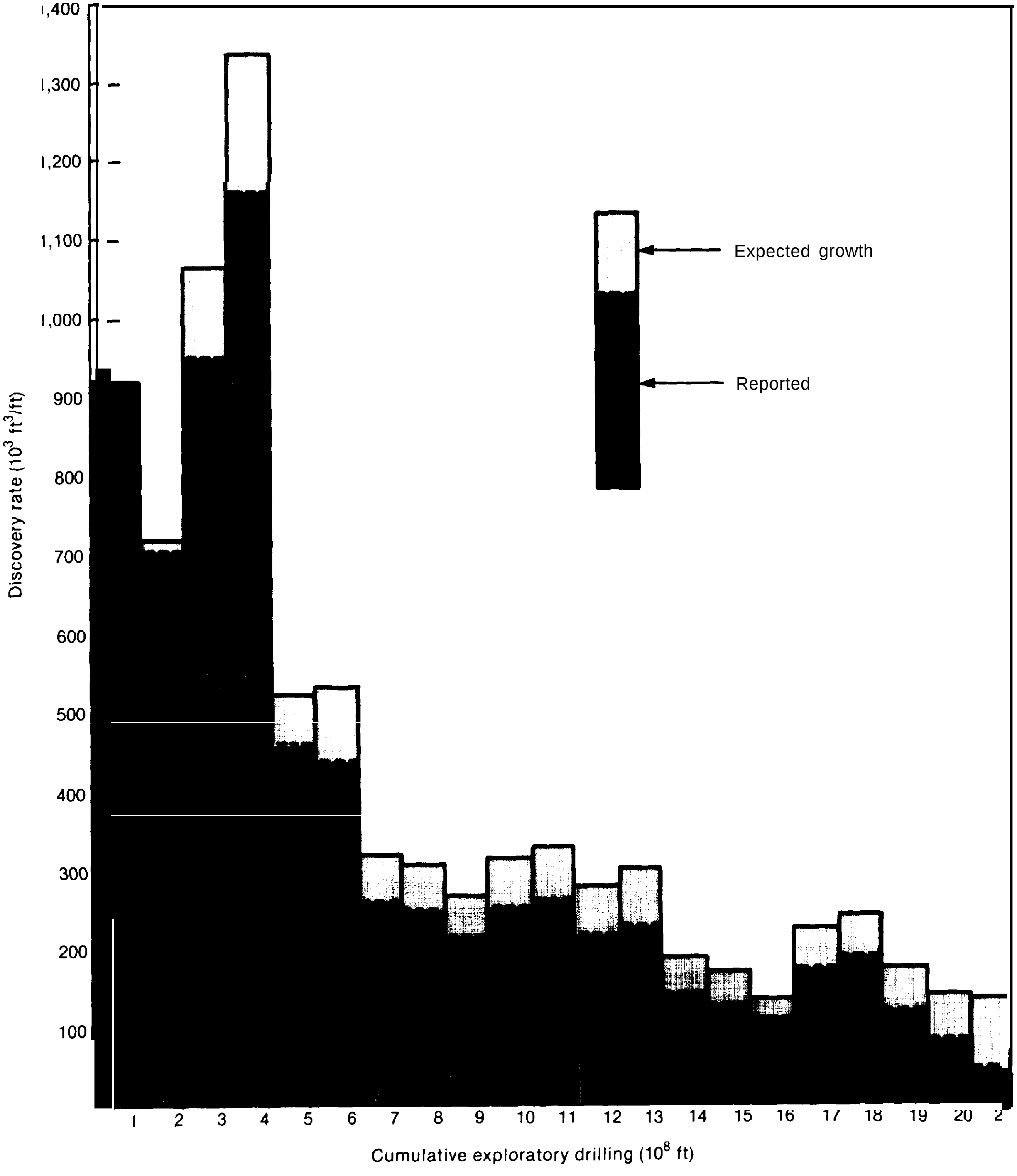
A variety of formulations can lead to an estimate of the resource base. One simple example is shown in figure 9, which plots the rate of discovery of natural gas, in thousands of cubic feet per foot of exploratory well drilled, versus the cumulative footage drilled. An exponential or other function can be fit to the historical data and extrapolated into the future. After *f* feet have been drilled, the area under the curve is equal to the total amount of gas discovered up to that point. * The total resource base can then be estimated by measuring the area under the curve when it has been extrapolated to the point where all recoverable gas has been located. This point is assumed to be:

- when the amount of gas discovered per foot of drilling falls below some chosen lower limit, or
- when the cumulative exploratory footage is judged high enough to have allowed essentially all prospective acreage in the United States to have been explored.

Although Hubbert's estimate of gas resources will be reviewed individually later, historical approaches to gas resource estimation **as a class** have some common limitations. First, areas that are not "mature' '-that do not have a substantial drilling or discovery history—are not represented in the historical data base and can be included in the assessment only if one is willing to assume they are part of the development process of a larger area and are not really independent. Consequently, Alaska is typically not included in the historical approaches, and the offshore areas are sometimes excluded as well. This limitation can be a problem with geologic as well as geographic categories; there is some question, for example, as to whether deep gas (below 15,000 ft) should be included in a "historical" resource estimate,

*Area = $\int_0^f$ (amount of gas discovered per foot drilled) d (cumulative feet drilled).

**Figure 9.-DiscoverieS of Recoverable Natural Gas in the Lower 48 States v. Cumulative Exploratory Drilling**




SOURCE: David H Root, USGS.

Second, since the resource estimates are totally dependent on extrapolations of the historical record, they depend heavily on the accuracy of this record. In the case of natural gas, this accuracy is probably poor. Through much of its discovery and production history, gas was usually a byproduct of the search for and production of oil and in the early years was often considered to be of very low value at best. Much gas was flared or otherwise wasted, production records were not kept, and gas discoveries often went unreported.

Third, all of these methods share the common assumption of all trend extrapolations: the future will be a reflection of the past. However, the "past" in the case of gas exploration and development has had interludes of radical change in the economic underpinnings and Government regulation of the industry and, to a certain extent, in the technology and geologic understanding driving the development process. Consequently, the historical approaches contain the implicit assumption either that the process of change will continue in the same manner in the future or that the physical nature of the resource base–unchanging except for changes wrought by development itself–is the main force driving gas development. In the long run, the physical nature of the resource base is seen as overwhelming the importance of volatile and transitory events or forces such as Government regulations and gas demand and price in determining the shape of the development curves. *

Fourth, it is difficult to define the economic, technologic, geographic, and geologic boundaries of a resource assessment based on historical trends. For example, data on the development of U.S. gas resources tracks a steady expansion of geographic coverage of exploration and production, an increase over time in the depth of wells, and a radical improvement in exploration technology. Did historical assessments of the U.S. gas resource done **before Anadarko** deep drilling include or exclude this deep resource? Will an assessment based on historical data account for a new Overthrust Belt type of development? To the extent that the historical curves capture past change, can they account for future changes? These questions are essentially unresolved. A common criticism of historical approaches is that they do not adequately capture the effect of new technologies and other changes. However, there is little agreement on what they **do** capture: opinions range from the full capture of future economic conditions to the capture only of gas that would be discovered and produced under the socioeconomic conditions of the last several decades[7]–in other words, from the top two-thirds of the McKelvey Box to only the top third.

It is worth noting that a substantial "surprise''--e.g., the unexpected discovery of a new geologic "horizon"—cannot be accurately predicted by a historical approach. This is because a true surprise will not have affected the previous discovery and production history in any discernible manner. Therefore, the historical method will yield the same resource estimate **no matter how big the surprise turns out to be.** (Although the geologic approach cannot predict such a surprise, it can incorporate its effects immediately for future predictions. )

Fifth, although "historical approaches" seek to extrapolate trends that are functions primarily of the resource base and are relatively unaffected by transient economic effects, the available data may be too aggregated to allow this. Generally, the data measure processes that are made up of two or more components, some of which **are** sensitive to market conditions. For example, the finding rate of new field wildcats may be used to represent the success of the discovery process. * However, finding rate data measure the combined success of at least two quite different kinds of exploration. The high-risk, high-payoff wildcats represent the search for large fields in untried areas

*In support of this view, it is worth mentioning that neither the major technical advances in exploration nor the opening of new territories since World War II were of sufficient importance to restore the 011 or gas discovery rate to pre-war levels; instead, the discovery rate continued a fairly steady downward drift for several decades, in seeming disregard of changing conditions and technology.

[6]Ibid.

[7]R. P. Sheldon, "Estimates of Undiscovered Petroleum Resources —A Perspective," U.S. Geological Survey Annual Report, Fiscal Year 1978.

*Discovery data generally is preferred over production data in a historical approach because the discovery cycle is always a few years older than the production cycle. Extrapolation to the end of the cycle consequently is less severe for discovery than for production.

and the exploration of older areas based on new geologic interpretations. The finding rate of these wildcats is a critical determinant of the long-term replenishment of proved reserves. The low-risk, low-payoff wildcats represent the redrilling of old, formerly uneconomic areas, or the clustering of exploratory drilling around a successful new strike. Because drilling statistics do not separate new field wildcats into different risk categories, the data on low-risk, low-payoff drilling, which is very sensitive to market conditions, dilutes and distorts the data on the drilling activity most relevant to ensuring the future of gas production.

The problem of using a single data series to measure a process that has two or more dissimilar components becomes more acute as larger and larger aggregations, geographical and otherwise, are used. Compiling the data for individual provinces may be useful because, for example, exploratory drilling on a local scale is more likely to be either high or low risk rather than a combination of the two. Thus, a disaggregated approach conceivably may be more successful than a national one in appropriately interpreting implications of a changing finding rate. On the other hand, the reduction in data points may tend to cause data series for small areas to be very erratic, and aggregation over larger areas may be necessary to detect long-term trends.

## Dealing With Uncertainty

It must seem obvious from past mistakes that petroleum resource assessment is a risky business. For example, tracts in the offshore south Atlantic shelf were recently leased to industry for millions of dollars (proceeds from the first two sales, lease sales 43 and 56, exceeded $400 million[8]) with an industry/Government consensus that large volumes of economically recoverable oil and gas were present, yet drilling results have thus far been negative.[9] Similarly, expected large fields in the Gulf of Alaska have failed to materialize under the drill. Conversely, drilling since 1975 in the Western Overthrust Belt has revealed a large, previously misunderstood potential for oil and gas. Even the calculation of proved reserves is uncertain and in some instances (e.g., Louisiana and Texas) has required extensive corrections in later years.

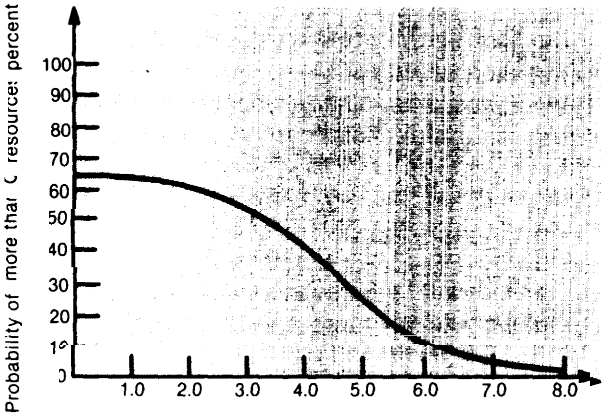
A major reason for the risk in resource assessment is that the presence of economically recoverable concentrations of petroleum requires the completion of an unbroken chain of events, each of which is difficult to predict. First, adequate amounts of source rock containing organic material must be present. Second, the temperature and pressure conditions must remain within a range capable of transforming the organic matter into petroleum. Third, geologic conditions must be right to allow the petroleum, once generated, to migrate. Fourth, permeable and porous rocks must be in the migration path to serve as a reservoir. Fifth, a geologic structure must be present to trap the petroleum so it can accumulate into commercial quantities. Not only the **availability** of the required conditions but also their **timing** are critical. The presence of an adequate trap, detectable with seismic or other search techniques, does not guarantee that the trap was present at the time of petroleum migration; if it was not, or if the trap was breached at some time after the petroleum entered the reservoir, the oil or gas would have escaped and would probably have reached the surface and dissipated.

Some estimators either (apparently) ignore uncertainty or acknowledge it only by expressing their results as an undefined or vaguely defined range (e.g., "optimistic/pessimistic"). Uncertainty **can** be dealt with explicitly and quantitatively in resource estimations, however. Resource estimates, or the individual factors used in estimating resources (e.g., volume of sedimentary rock, hydrocarbon yield factor), can be expressed as probability functions instead of point estimates or ranges. For example, figure 10 illustrates a hypothetical probability function for the undiscovered recoverable gas resources of a single province. The curve shows the probability that there are more than Q undiscovered resources in the province. * "Probabilistic estimates" such as these

[8]USGS Open-File Report 82-15, South Atlantic Summary Report 2, May 1982.
[9]Ibid.

*The probability is not 100 percent at Q = O because there is a finite probability that the province does **not** have "more than O resources;" in a totally unexplored province, this probability of zero recoverable resources may be quite large.

**Figure 10.—Probability Distribution for Undiscovered Recoverable Gas Resources in a Province**




NOTE: "More than" cumulative distribution function.

SOURCE: David H. Root, USGS.

cannot be directly added (or, in the case of estimates for volumes and yield factors, multiplied) to form aggregate resource estimates, such as an estimate of total U.S. gas resources. Instead, they are added statistically; one commonly used technique is called Monte Carlo simulation (see box C).*

*In Monte Carlo simulation, a value is selected at random from each of the separate probability functions that are the components of the resource estimate (e. g., for a nationwide assessment, the components are the individual province assessments; for a volumetric resource assessment, the components are the volume of sedimentary rock and the hydrocarbon yield factor). These values are then combined arithmetically to form a single point estimate of the resource base (for the nationwide assessment, the values from each province are added; for the volumetric, the values selected for volume and yield are multiplied). This procedure is repeated many times, each time producing a new point estimate, until a probability function for the resource base is formed.

Although probabilistic methods are useful for displaying some of the uncertainties associated with resource estimation, the language used to describe the results of these methods is often misunderstood by a lay audience. It is critical to remember that the accuracy of probabilistic estimates is limited by the extent to which the estimators' model of the physical universe is a correct one. In estimates such as those of USGS, the "95th percentile" estimate should **not** be interpreted as meaning that there actually is a 95 percent probability that the resource base is larger than this estimate. It should **instead be interpreted to mean only that the assessors, with whatever limitations their geologic "mindsets" and their limited data may impose on them,** believe that there is such a 95 percent probability. This difference may seem subtle, and it certainly is not kept secret by the estimators, but it is nevertheless important.

# COMPARISON AND REVIEW OF INDIVIDUAL ESTIMATES

Although many readers may be aware only of the work of USGS and perhaps that of M. King Hubbert, assessments of the U.S. natural gas resource base are quite numerous and use a wide variety of approaches. Table 6 lists some of the more recent estimates of the "ultimately recoverable resource' '—the total amount of gas that will be produced. The table also shows estimates of the recoverable resource remaining as well as the resources not yet added to proved reserves. The wide range of mean estimates for the remaining resources in the Lower 48 States—244 to 916 trillion cubic feet (TCF)—implies, in turn, a wide range in the outlook for future gas production, especially in the longer term.

Many available resource assessments are poorly documented and cannot be evaluated. OTA has reviewed some of the more widely known estimates, however, including those of USGS, PGC, the RAND Corp., and M. King Hubbert.

## U.S. Geological Survey

Recent estimates of undiscovered gas resources by USGS, as presented in 1975 in "Circular 725"[10] and more recently in 1981 in "Circular 860,"[11] are probably the most widely used gas

[10] B. M. Miller, et al., *Geological Estimates Of Undiscovered Recoverable Oil and Gas Resources in the United States,"* USGS Circular 725, 1975.

[11] Dolton, et al., Op. cit.

[illegible]

*A small field may be defined as one with an ultimate production of less than 10 million barrels of oil, 60 billion cubic feet of natural gas, or comparable amounts of oil and gas energy expressed as barrels of oil equivalent (BOE), using 6,000 cubic feet of gas as equal to 1 barrel of oil.

resource estimates. The most recent estimate uses a Delphi-type approach whereby teams of geologists arrive directly at resource estimates for individual petroleum provinces through a subjective assessment of the available geological data and the results of a variety of estimation approaches (including volumetric, play analysis, and other geologic methods as well as finding-rate analyses and other historical methods).

The estimates are probabilistic, that is, each is presented as a curve that shows the probability that the actual resource base is larger than any particular value (see fig. 10). Thus, the 95th percentile estimate reflects the USGS assessment that there is a 95 percent probability that the actual resource base is at least this large. Because only those resources that are virtually certain to exist are included, this estimate would be considered the pessimistic extreme of the range of estimates. The individual province estimates are added statistically, using a Monte Carlo technique, to achieve a national estimate. As described previously (box A), the "high-low" range described by the 5th and 95th percentiles is narrower than would be the case if the interdependence of individual province estimates could be taken into account. However, the potential problem was described as minor by the experts OTA talked with, largely because of USGS' selection of province boundaries.

The USGS assessment is unusual in that individual probabilistic estimates are available for each of 137 provinces, providing a very fine level of detail. Also, detailed information files on individual provinces are open to the public at USGS' Denver facility. As with most geologic estimates, the USGS estimate is not meant to include all resources that may be recoverable at any time, but is instead limited to the resources that "will be recoverable under conditions represented by a continuation of price-cost relationships and technological trends that prevailed at the time of

**Table 6.-Alternative Estimates of Ultimately Recoverable and Remaining Natural Gas in the United States (TCF)**

| Estimator | Publication date | Ultimately recoverable resources: Lower 48 | Ultimately recoverable resources: Total U.S. | Remaining resources Lower 48, 1983[a] | Remaining resources not yet-added to proved reserves, Lower 48, 1983[b] |
|---|---|---|---|---|---|
| Mobil | 1975 | — | 1,076-1,241-1,456 | — | — |
| Garrett | 1975 | — | 1,313 | — | — |
| Wiorkowsky | 1975 | 1,221 -1,289-1 ,357 | — | 595-663-731 | 421-489-557 |
| Bromberg/Hartigan | 1975 | 966[c] | — | 340 | 166 |
| Exxon Attainable | 1976 | — | 917-1,112-1,577 | — | — |
| Shell (1) | 1978 | 946 | 910-1,075-1,260 | 320 | 146 |
| Shell (2) | 1984 | 1,150[d] | 1,265d | 525[d] | 350[d] |
| IGT | 1980 | — | 1,288-1,798 | — | — |
| PGC | 1983 | 1,542 | 1,711 | 916 | 742 |
| Hubbert (1) | 1980 | 870 | — | 244 | 70 |
| Hubbert (2) | 1980 | 989' | — | 363 | 189 |
| RAND | 1981 | 902 | 989 | 283 | 109 |
| USGS | 1981 | 1,400 | 1,422-1,541-1,686 | 774 | 600 |

aApproximate cumulative Lower 48 production through 1962 was 631 TCF, of which about 5 TCF is in underground storage. "Remaining resource" is "Lower 48" (ultimately recoverable) column value minus 631 TCF plus 5 TCF.
Lower 48 proved reserves assumed to be 169 TCF on Dec. 31, 1982 (excluding underground storage).
cOriginal estimate for onshore gas only. Total arrived at by adding USGS (mean) estimate for ultimately recoverable offshore gas in Lower 48 (235 TCF)
'Estimate includes 52 TCF for additional resources obtainable with old gas decontrol.
'Based on an analysis of finding rates by David Root, USGS.
SOURCE: Mobil—J. D. Moody and R, E. Geiger, "Petroleum Resources; How Much Oil and Where," Technology Review, March/April 1975. Verbal comments by John Moody at a FPC presentation, Apr. 14, 1975.
Garrett-R. W. Garrett, "Average of Some Estimates by Major Oil Companies and Others, 1975, " oral presentation at Executive Conference of the American Gas Association, June 9-11, 1975, cited in Potential Gas Committee, *A Comparison of Estimates of* Ultimately *Recoverable Quantities of Natural* Gas In the *United States,* Gas Resource Studies No. 1, Potential Gas Agency, April 1977.
Wiorkowski-J J Wiorkowski, *Estimation of Oil and Natural Gas Reserves Usirn Historical Data Series: A Critical Review,* unpublished manuscript, 1975, cited in J. J Wiorkowski, "Estimating Volumes of Remaining Fossil Fuel Resources: A Critical Review, " in J. *Am, Stat. Assoc., vol. 76, No. 875,* September 1961
Bromberg/Hartigan-L. Bromberg and J. A Hartigan, Report to the *Federal Energy Administration,* unpublished manuscript, 1975, cited in Wiorkowski (1981), noted above.
Exxon—Exxon Co , U. S. A., Exploration Department, "U.S. Oil and Gas Potential, " March 1976 *Oil and Gas Journal,* "Exxon Says U.S. Still Has Vast Potential, " Mar. 22, 1976,
Shell (1)—C. L. Blackburn, Shell Oil Co., "Long-Range Potential of Domestic Oil and Gas," presented at NAPIA/PIRA Fall Conference, Boca Raton, Fla., Oct. 19, 1978, Oil *and Gas Journal,* "Shell: Alaska Holds 58% of Future U.S. Oil Finds, " Nov. 20, 1978.
Shell (2)—R. A. Rozendal, *Convention/ U.S. Oil and Gas Remaining To Be Discovered: Estimates and Methodology Used by Shell Oil Company,* draft, Aug. 1, 1964, Shell Oil Co.
IGT—J. D. Parent *A Survey of* United States *and Total World Production, Proved Reserves, and Remaining Recoverable Resources of Fossil Fuels and Uranium,* Institute of Gas Technology, Chicago, August 1960, cited in American Gas Association, "Energy Analysis A Comparison of U S. and World Remaining Gas and Oil Resources," Aug, 7, 1981.
PGC– Potential Gas Agency *Potential Supply of Natural Gas in the United States (as of Dec. 31, 1982),* Colorado School of Mines, June 1983.
Hubbert (1) (2)—M, K. Hubbert, "Techniques of Prediction as Applied to the Production of Oil and Gas," in Oil *and* Gas *Supply Modeling, S. I.* Gass (cd,), National Bureau of Standards Special Publication 631, May 1982.
RAND—R. Nehring with E. R. Van Driest 11, The *Discovery of Significant Oil and Gas Fields in the United States, R.2654/1* USGS/DOE, RAND Corp , January 1981,
USGS—G L Dolton, et al., *Estimates of Undiscovered Recoverable Convention/ Resources of Oil and Gas in the United States,* U.S. Geological Survey Circular 660, 1981

assessment (1980)."12 Consequently, resources that are currently in fields that are too small, under too much water, under geologic conditions that are too difficult, or are otherwise not economically recoverable are not reflected in the current estimates but could be expected to enter the recoverable resource base in the future if gas prices rise and technology improves significantly.

In contrast to the approach for estimating resources in undiscovered fields, USGS calculated the remaining resources in undiscovered pools in known fields and expansion of the proved areas of known pools* by using a simple extrapelation from historical records of gasfield growth.[13] Field growth is a significant source of gas, and USGS calculated the resources in this category to be about 172 TCF, or over one-fifth of the remaining gas resources. Unfortunately, the USGS approach to assessing this source is problematical because the historical growth rates of known fields have tended to be extremely variable, and the characteristics of fields discovered recently, and calculated by this method to yield

[12] Ibid,

*These resources are called "inferred reserves' in the USGS assessment and are equivalent to the "probable potential resources" in the PGC assessment.

[13] Ibid, app. F.

the most growth, are quite different from the fields that supplied the historical data. In OTA's opinion, there is a significant potential for error in this approach.

in USGS' 1975 resource estimate, the economic boundary of recoverable resources also proved to be a problem; a survey of the assessment team revealed considerable differences between their various interpretations of the meaning of the boundary definition .14 Although OTA undertook no formal survey for the 1981 **assessment, informal talks with analysts close to the assessment** process lead OTA to believe this problem still exists. For example, several analysts believe that part of the offshore resource in the USGS assessment is far too expensive to be developed unless gas prices escalate substantially. If this is correct, these resources are subeconomic, according to USGS's definition, and should not be included in the estimate of recoverable resources.

Another potential problem area in the assessment is the boundary between "conventional" and "unconventional" resources. The USGS estimate is of "undiscovered recoverable **conventional** resources (our emphasis)" and excludes "gas in low permeability ('tight') reservoirs" and other so-called unconventional resources.[15] The precise meaning of the exclusion is unclear, however. In moving towards lower and lower permeabilities, there is no general consensus about where "conventional but low permeability reservoirs" end and "unconventional 'tight' reservoirs" begin, and USGS has not defined a threshold value of permeability to separate the two.

Circular 860 does imply, however, that some undiscovered gas in low-permeability reservoirs was excluded from the estimated conventional resource base even though the gas could currently be defined as economically recoverable. Consequently, all else being equal, the USGS estimate should be expected to be smaller than estimates that include **all** economically recoverable gas resources.

It also is commonly believed that USGS' Delphi technique, described by USGS as relying on reviews of the results of a variety of approaches, relies primarily on the results of volumetric analysis. This reliance on the volumetric approach is probably due to data limitations. The USGS data base, although substantial, is generally limited to public data.[16] Volumetric analysis has often been associated with relatively optimistic resource assessments.

## Potential Gas Committee

The estimates of "potential" gas resources–recoverable resources that have not been produced or proved—by the PGC represent the gas industry counterpoint to the USGS estimate. *

PGC's most recent estimate of the total U.S. potential resource—876 TCF for the end of 1982[17] –-represents a decrease from the year-end 1980 estimate.[18] Because this decrease is balanced by additions to proved reserves during the period, the old and new estimates are similar in their estimates of total ultimately recoverable resources.

The PGC estimation procedure is generally structured like a volumetric analysis in that the PGC analysts separately estimate the volume of potential gas-bearing reservoir rock and a yield factor (amount of gas per volume of rock) and multiply the two to arrive at an initial resource estimate. The analysis combines aspects of other geologic approaches, however. It is also strengthened by the separate estimation of gas potential for 11 distinct geographical areas within the Lower 48 States, for three distinct categories of resource within the areas according to their state of development, * for offshore and onshore re-

[14] Personal communication with John Schanz, Congressional Research Service.

[15] Dolton, et al., Op. cit.

[16] G Dolton, USGS, presentation at RAND workshop on estimating U.S. natural gas resources, Washington, DC, Mar. 1-3, 1982.

*PGC is composed of members and observers from gas producers, pipelines, and distribution companies and observers from the American Gas Association, Department of Energy, Gas Research Institute, and other public and private organizations. The actual estimating workgroups consist mainly of industry employees and consultants, but State geological surveys are well represented, and some of the groups include personnel from Federal agencies and from universities.

[17] News release, Potential Gas Agency, Feb. 26, 1983.

[18] Potential Gas Agency, *Potential Supply of Natural Gas in the United States (as of Dec. 31, 1980),* May 1981.

*The categories are "probable," "possible," and "speculative" resources. Probable gas results from the growth of known fields, possible gas is associated with the projection of plays or trends of a producing formation into a less well-explored area of the same geologic province, and speculative gas is from formations or provinces that have not yet proven to be productive.

sources, for resources above and below a depth of 15,000 ft in the onshore portion, and for resources above and below water depths of 200 meters to a maximum of 1,000 meters offshore. The estimates "include only the natural gas resource which can be discovered and produced using current or foreseeable technology and under the condition that the price/cost ratio will be favorable."[19] These conditions are similar to those adopted by USGS, but what constitutes a "favorable price/cost ratio" remains unclear. The large proportion of deep resources incorporated in the estimate may imply, however, that PGC has included resources that will require prices above present market clearing levels.**

The PGC volumetric estimation procedure is considerably more sophisticated than early techniques that were based on total volumes of sedimentary rock, In the PGC analysis, the volumes of potential gas-bearing reservoir rock are estimated by adding up estimates of individual traps and trap sizes where sufficient data is available. According to PGC's methodology description,[20] techniques such as play analysis and field number and size approaches are used to construct an areawide volume estimate based on a variety of existing geological data. Yield factors (gas volumes/rock volumes) are then calculated by selecting appropriate analogs from producing areas and adjusting the yields to account for geochemical factors such as the thermal history of the source rocks. Finally, the analysts are asked to multiply the (volume) X (yield) estimates by their assessments of the probabilities that traps actually exist and that an actual accumulation of gas has occurred.

The analysts also are asked to separately estimate "optimistic," "most likely, " and "pessimistic" volumes of gas in a manner similar to that of the USGS. In contrast to USGS, however, PGC publishes only the "most likely" estimates. The other estimates are apparently used for review purposes only.

[19]1 bid.

* *Orr the other hand, the actual price requirements for producıng deep gas under tree market conditions are uncertain, and it is possible that much of PGC's deep potential is producible at prices not tar removed from today's.

'('1 bid.

Because PGC publishes only the results of its analyses and does not release any internal details of the resource calculations (except for general methodology descriptions), and because it is essentially a gas industry organization, the credibility of PGC's resource estimates may be questioned. In OTA's opinion, however, the PGC estimates should be taken as a serious effort at resource assessment by analysts with excellent access to exploration data. The estimating workgroups, although composed mostly of industry employees, have a sufficient number of other participants-and a sufficient divergence of incentives within different segments of the industry—to prevent any attempts to subvert the assessment process significantly. Also, the long-term professional history of the organization (since 1966) and the oversight of the Colorado School of Mines are substantial arguments for accepting the PGC estimates as honest reflections of the professional judgment of the organization.

An advantage of the PGC estimates is that the basic methodology has been applied, with evolutionary changes, for 16 years. Table 7 shows the eight estimates of ultimately recoverable gas resources in the Lower 48 States produced by PGC since 1966. The consistency of these estimates is high. In fact, given the advances in technology and the major additions to the known boundaries of conventional gas supply that have occurred in the past 16 years, * the mildness of

*For example, the addition of the Western Overthrust Belt due largely to advances in seismic technology, and the addition of large amounts of gas from low permeable formations due to advances in fracturing.

**Table 7.—Comparison of Potential Gas Committee Estimates of Ultimately Recoverable Gas Resources in the Lower 48 States**

| Estimate as of year end | Ultimately recoverable resources (in TCF) |
|---|---|
| 1966 . . . . . . . . . . . . . . . . | 1,283 |
| 1968 . . . . . . . . . . . . . . . . | 1,426 |
| 1970 . . . . . . . . . . . . . . . . | 1,498 |
| 1972 . . . . . . . . . . . . . . . . | 1,446 |
| 1976 . . . . . . . . . . . . . . . . | 1,396-1,421-1,446 |
| 1978 . . . . . . . . . . . . . . . . | 1,550 |
| 1980 . . . . . . . . . . . . . . . . | 1,502 |
| 1982 . . . . . . . . . . . . . . . . | 1,542a |

aApproximate—A portion of the difference between the 1980 and 1982 estimates is due to discrepancies between the proved reserve values computed by AGA (used for the 1960 calculation) and the EIA (used for the 1982 calculation)

SOURCE Potential Gas Agency, Potential Supply of *Natural Gas in the United* States (as of *Dec.* 31, 1980), May 1981, and Potential Gas Agency, news release, Feb. 26, 1983 the upward trend in the estimates over this time period implies a movement toward more conservative estimates. This conservatism is particularly interesting in light of PGC's resource estimates being among the most optimistic of the major assessments.

In its 1982 assessment, PGC attempted to isolate that portion of the estimated potential resource that occurs in tight formations—tight sands with permeability levels less than 0.1 millidarcy (conforming to the Federal Energy Regulatory Commission definition for gas eligible for incentive pricing) and Devonian shales. A series of areawide estimates were produced for depths above and below 15,000 ft. The "tight" portion of the U.S. potential gas resource was estimated to be about 20 percent of the total, or 172 TCF,

This estimate is highly significant for two reasons. First, it demonstrates graphically the long-term growth in the "ultimately recoverable" gas resource base and offers some support to the optimistic view that advancing technology can overcome at least some of the effects of resource depletion, Second, to the extent that other resource assessors may have excluded tight gas from their estimates, it may bring the PGC estimate closer to the "mean" of gas resource estimates in table 6. Unfortunately, the definitions of the boundary conditions of most of the assessments in table 6 are not sufficiently clear to ascertain whether tight gas **that is recoverable under the PGC boundary conditions were excluded or included.** A possible exception, however, is the USGS assessment, whose stated boundary conditions appear to be more restrictive than PGC's. It is probable that some of the tight gas included in the PGC estimate was not included in the USGS estimate.

## RAND/Nehring

Richard Nehring of the RAND Corp. has produced an assessment of conventional U.S. oil and gas resources by a method that stresses an evaluation of the discovery of significant fields.[21] The assessment incorporates a variety of approaches:

21 R. Nehring with E. R. Van Driest II, *The Discovery of Significant Oil and Gas Fields in the United States,* RAND Corp. Report R-2654/I-USGS/DOE, January 1981.

1. To estimate the growth of reserves in known fields, a combination of methods were used, including extrapolating by historical field growth factors and by more analytical approaches that used available geologic information and known production practices.
2. To estimate the amount of resource remaining to be discovered in known producing plays, an approach based on extrapolating historical trends was used. The key to this approach was the establishment of a data base containing production and reserve values, the year of discovery, discovery method, trap type, depth, and other data for virtually every petroleum field discovered in the United States by 1975 larger than class C (10 million to 25 million barrels-of-oil-equivalent). Despite the emphasis on the historical record, however, the approach also incorporates geologic methods based on play analysis.
3. play analysis was used to estimate the resources in new plays in mature regions.
4. Depending on the availability of data, a variety of approaches were used to estimate resources in the frontier (ranging from volumetric analysis to field number and size approaches).

The estimates for new plays in mature regions and frontier areas were "risked" (i.e., the probability that there are no recoverable resources in the play is taken into account), and the assessments of undiscovered resources were expressed as probability distributions in a manner essentially identical to that used by USGS.

The RAND assessment has been criticized because of its alleged failure to define the process by which its massive data base is translated into resource base conclusions. In OTA's opinion, the description of the methodology that appears in the RAND report is indeed brief and generalized and gives no specific examples of the assessment process. However, this failure is endemic to resource assessments as a class. Even the PGC assessment, which describes its analytical process in some detail, publishes no backup data and provides only the sketchiest details of the geologic reasoning behind its regional results. in contrast, the RAND assessment explicitly defines the historical and geologic reasons for its regional assessments and identifies—and argues against—opposing views. This approach allows at least a partial evaluation of the assessment, whereas most assessments can be evaluated only to the extent of either accepting or rejecting the final estimates.

At the core of Nehring's argument for his quite pessimistic estimate is the thesis that the geologic possibilities for finding substantial new oil and gas resources in the United States have been largely exhausted. Nehring identifies four major hypotheses about where significant amounts of oil and gas may yet be found–in fields below 15,000 ft in depth (for natural gas only); in subtle, difficult-to-detect stratigraphic traps; in small fields; and in frontier areas, including the Eastern and Western Overthrust Belts–and argues against high optimism in each, with the possible exception of the frontier areas. The four hypotheses and Nehring's countering arguments are summarized in box D. A more detailed discussion of these hypotheses is presented later in this chapter.

A second facet to this argument is that this exhaustion of geologic possibilities is reflected in the recent (disappointing) history of exploratory drilling. Nehring argues that optimistic assess-

**Box D.—Rand Assessment's Arguments Against a Large Undiscovered Oil and Gas Resource Base**

**Deep Discoveries**

- **Major argument: Deep sediments are relatively unexplored. The few exploratory wells that have** been drilled have been highly successful.
- **RAND rebuttal: Physical and chemical conditions at these depths can be poor for methane stability. Reservoir porosity is often lacking. The area with deep sediments is a small fraction of total prospective sedimentary area. Most of the potentially productive structures in several basins have already been tested.**

**Stratigraphic Traps**

- **Major argument: Exploration has focused on structural traps, leaving significant opportunities in subtle stratigraphic traps.**
- RAND **rebuttal: Actually, considerable attention has been paid to stratigraphic traps in the Anadarko, Permian, and other basins. Aside from the stable interior provinces, multiple stratigraphic traps are unlikely. Because stratigraphically trapped reservoirs tend to be thin, large fields would cover large areas and would likely have been discovered. Large traps would be vulnerable to breaching and other causes of petroleum loss.**

**Very Small Fields**

- **Major argument: Because small gas fields were previously subeconomic, their discovery went unreported. Many more small fields exist than indicated by historical experience, and they forma sizable part of the recoverable gas resource.**
- **RAND rebuttal: Future reliance on small fields is based on assumption only; there is neither historical nor geologic argument to back it up. Also, because giant and large fields are two-to-four orders of magnitude larger than fields small enough to have been ignored in the past, there would have to be many tens of thousands of such fields to make any significant difference.**

**New Frontiers**

- **Major argument: Areas such as Alaska, the offshore Lower 48 States, and the Overthrust Belts have not been extensively explored and offer the potential for many significant discoveries.**
- **RAND rebuttal: Yes, but the small number of exploratory wells drilled in the Gulf of Alaska, the Outer Banks of California, the eastern Gulf of Mexico, the Southeast Georgia Embayment, and Baltimore Canyon are sufficient to severely dampen optimism for these areas. Some very promising areas do remain, however, including the deeper Gulf of Mexico, offshore Ventura Basin, and others.**

SOURCE: Office of Technology Assessment, based on R. Nehring, The *Discoveryof Significant Oil andGas Fields* in the United States, R-2654/1-USGS/OOE, RAND Corp., January 1981.

ments simply do not bear up under the weight of the question, "Is it likely that we will find as many large fields as this assessment implies must be there?" For example, table 8 presents a proposed field size distribution that would yield an undiscovered petroleum (oil plus gas) resource equal to that predicted in the 1975 USGS (Circular 725) onshore assessment. This distribution would also be approximately equivalent to the more recent 1981 (Circular 860) USGS assessment, although the more recent assessment is slightly more optimistic. in the table, the proposed distribution is compared to actual field discovery statistics for 1971 through 1978. The last column shows how long it would take to find the necessary number of fields of each size category if the annual discovery rates of 1971 through 1978 continued for the life of the resource. In Nehring's opinion, the number of large fields that would have to be discovered to fulfill the USGS assessment is too large to be credible. The long "times of discovery" in the table appear to reinforce this opinion. Unfortunately, none of the reviewed assessments defined a timeframe for complete discovery of the resource base, and an interpretation of the compatibility of a particular resource base/discovery rate combination is anything but straightforward. Also, the cessation of the American Gas Association's (AGA) reserve data (particularly reserve additions from new field wildcats) in 1979 prevents an easy check on whether post-1978 new field discoveries are ahead of discoveries during 1971-78; if they were, an argument could be made that the times in table 8 were misleadingly long because the assumed discovery rate was too low. On the other hand, the assumption in table 8 of a constant annual discovery rate for new gasfields over a **50-** to 100-year period appears optimistic, even if the assumed rate is a bit low at the beginning of the period. This is because discovery rates per foot drilled appear likely to decline during this period, and a constant annual discovery rate thus implies an ever-increasing rate of new field wildcat drilling in an increasingly hostile **and expensive environment.**

**One portion of the** RAND assessment that now seems particularly suspect is the median estimate for field growth. The estimate (67 TCF) was only about one-third of the field growth estimates of USGS and PGC, a seemingly surprising difference **considering the substantial amount of geologic knowledge available. * Recent large reserve additions from field growth make it clear that this estimate was too low. * ***

## Hubbert

As noted earlier, M. King Hubbert is one of a considerable number of analysts who have used a historical approach—fitting curves to past trends in production, reserve growth, discoveries, and

*However, the recent controversy over the magnitude of additional gas that might be obtainable from old gas decontrol demonstrates that the availability of extensive geologic knowledge does not guarantee agreement over resources present.

**Nehring acknowledged this problem to OTA in a recent telephone conversation.

**Table 8.—Field Discovery Implications of USGS Circular 725, Onshore Lower 48 Undiscovered Petroleum Resource**

| Field size[a] | Potential field size distribution: USGS Circular 725 | Actual field discoveries 1971-75 | 1976-78 | Implied time to find USGS undiscovered resource, constant annual discovery rate at 1971-78 average (years) |
|---|---|---|---|---|
| AAAA (>500/>3,000) | 11 | 0 | 1 | 88 |
| AAA (200-500/1,200-3,000) | 44 | 0 | 0 | Large but indeterminate |
| AA (100-200/600-1,200) | 94 | 7 | 1 | 94 |
| A (50-100/300-600) | 199 | 7 | 3 | 159 |
| B (25-50/150-300) | 375 | 15 | 8 | 130 |
| C (10-25/60-150) | 977 | 44 | 22 | 118 |
| D (1-10/6-60) | 6,000 | 455b | — | 66 |
| E (< 1/<6) | 70,000 | 3,041[b] | | 115 |

aValues in parenthesis are sizerange in millions of barrels of oil equivalent (mmboe)/billions of cubic feet of gas (BCF).
b1972-76 Committee on Statistics of Drilling of the American Association of petroleum Geologists.

SOURCE: Office of Technology Assessment, based on R. Nehring, *The Discovery of Significant Oil and Gas Fields in the United States,* RAND Corp. report R-2654/l-USGS/DOE, January 1961. Also, personal communication, Richard Nehring.

so forth-to petroleum resource assessment. However, Hubbert's estimates must be accorded special attention. In 1962 Hubbert predicted that U.S. oil production would peak in 1969 and decline thereafter. He then held his ground in the face of substantial criticism until the peak actually did occur, only a year later than he said it would. From that time, his assessments of petroleum trends and resources have received considerably more attention and respect.

Hubbert's most recent estimate of the size of the natural gas resource base was made in 1980.22 He estimates the ultimate cumulative production of conventional natural gas (Q~) for the Lower 48 States to be approximately 870 TCF. This is a remarkably low estimate given cumulative production to date of about 631 TCF and proved reserves of about 167 TCF; * * if correct, it leaves only about 70 TCF remaining to be added to reserves from the growth of known fields (calculated by USGS to be 172 TCF) and new field discoveries. In other words, Hubbert's assessment implies that the precipitous declines of the early 1970s in Lower 48 proved reserves will resume again almost immediately, with subsequent drastic consequences for production rates within only a few years.

in his 1980 assessment, Hubbert obtained five separate estimates, using basically three approaches (table 9). In his first approach he derived equations for the magnitudes and rates of change of gas production and discoveries by noting some simple boundary conditions for the production cycle* and fitting a second order equation * * to these conditions. By further manipulating the equation obtained by this exercise, Hubbert derived three separate but related methods of estimating $Q_m$, two involving the curve of cumulative discoveries and one involving production rate as a function of cumulative production.

In his second approach Hubbert assumed that the ratio of the discoveries of natural gas to those of crude oil will tend to remain stable, allowing the gas resource base to be calculated as a simple function of the oil resource base.

The third approach involved extrapolating the declining finding rate for gas out to the point where exploratory drilling ceases and taking the area under the curve, as discussed in the earlier section on historical approaches to resource estimation (see fig. 8).

Hubbert's work has been the subject of numerous critical appraisals.[23] This discussion will not attempt to review the appraisals but will incorporate some of their key points.

Of Hubbert's five estimates, the first three involve the assumption that the curves of **declining production and proved reserves will be the mirror image of the curves of the (increasing) first portion of the resource development cycle. This derives from Hubbert's satisfaction with the "fit" of the simple quadratic equation he uses to approximate the curve of $\frac{\partial Q}{\partial t}$ v. Q. Aside from the criticism associated with all historical approaches**

*[2]Hubbert, op. cit.

* *As of the beginning of 1983.

**Table 9.—Hubbert's 1980 Estimates of Ultimately Recoverable Gas Resources in the Lower 48**

| Method of estimation | $Q_m$ (TCF) |
|---|---|
| 1. Extrapolating the plot of production rate as a function of cumulative production . | 810 |
| 2. Estimating the approach of cumulative discoveries to $Q_m$ as time approaches 00 . . | 871 |
| 3. Finding the equation of cumulative discoveries versus time . . . . . . . . . . . . . . . . . . | 840 |
| 4. Using oil resource estimate and assuming stable gas/oil discovery ratio. . . . . | 876-896 |
| 5. Fitting and extrapolating the curve of discoveries per $10^8$ feet of exploratory drilling . . . . . . . . . . . . . . . . . . . . | 989 |

SOURCE: Office of Technology Assessment, based on M. K, Hubbert, "Techniques of Production as Applied to the Production of Oil and Gas, " in *Oil and* Gas *Supply Modeling, S.* I. Gass (cd,), National Bureau of Standards Special Publication 631, May 1982,

*Cumulative production Q is zero at the beginning of the cycle and $Q_m$ at the end; the production rate ~~ is zero when Q = O and also when $Q = Q_\infty$).

$$** \frac{\partial Q}{\partial t} = C_1Q + C_2Q^2$$

[23]For example, L. S. Mayer cites three: D. V. P. Harris, "Conventional Crude Oil Resources of the U. S.: Recent Estimates, Methods for Estimation and Policy Consideration, " *Materials and Society 1,* 1977; N. Uri, "A Reexamination of the Estimation of Undiscovered Oil Resources in the U.S.," DOE/TM/ES/79-03, 1979, EIA; L. Mayer, et al., "Modeling the Rates of Domestic Crude Oil Discovery and Production, " report to the EIA, Princeton University, Department of Statistics, 1979. (In comment on J. J. Wiorkowski, "Estimating Volumes of Remaining Fossil Fuel Resources: A Critical Review, " *J. Am. Stat. Assoc.,* September 1981)

–that the future does not have to look like the past, and more often than not doesn't-–Hubbert never explores the possibility that he could achieve an equal or better fit with a different equation and thereby calculate a different Q~. Critics have shown, for example, that the resource base values obtained from fitting a curve to oil production data are sensitive to the type of curve used, and that Hubbert's assumed curve is not the best choice.[24] Although Hubbert's curve for oil **discovery** is more satisfactory, it may be that the less mature gas discovery curve is also flawed. *

The assumption of the fourth estimate, that the ratio of gas discoveries to oil discoveries will remain stable, appears to be very weak. The great majority (85 percent) of gas discoveries today are not associated with oil, and it is the consensus of many geologists that a large portion of the remaining gas resource lies below 15,000 ft in a physical environment hostile to the preservation of oil. A method predicated on stable gas/oil ratios would appear to guarantee an overly pessimistic gas resource base estimate.

in the last estimate, Hubbert fits an exponential curve to a historical plot of finding rate (the ultimate volume of gas to be produced from fields discovered by $10^8$ ft of exploratory drilling) versus cumulative exploratory drilling, by requiring the curve to pass through the last data point and by requiring the area under the fitted curve to equal the area under the historical data plot (see fig. 8). This estimate has several serious problems. First the curve does not fit the data because it virtually ignores the "form" of the data and concentrates instead on the last data point.[25] Second, the estimate is very sensitive to this last data point, yet the magnitude of the point is the sum of a value (reported new field wildcat discoveries) that may vary with economic conditions* and with the state of depletion of the resource base plus a second value (reserve growth after the initial reporting period) that is, at best, a gross approximation. * * Third, as with the first three estimates, Hubbert makes no attempt to explore the possibility that he could achieve a better "fit" with a different curve. His choice of a negative exponential curve is an assertion made several times but unsupported by reasoning in his text.

An interesting observation about this last estimate is that despite the fact that the fitted curve is well under the trend line of the last several units of drilling—an ingredient for an overly conservative estimate—the estimate is considerably higher than the four other estimates in table 9.

24 E.g., J.J. Wiorkowski, 1981, "Estimating Volumes of Remaining Fossil Fuel Resources: A Critical Review, " ). *Am. Stat. Assoc.*, September 1981, vol. 76, No. 875.

*The reasoning here is that the oil discovery curve gives more satisfactory results than the oil production curve because discovery is more advanced in its overall cycle. The less advanced, or less "mature," the curve, the less satisfactory will be the results.

'25 Harris, 1977, Op. cit.

*For example, a period of high risk exploratory effort-responding to economic conditions that favor this sort of activity–will tend to yield high discovery rates, whereas one of lower risk effort responding to different conditions generally will yield lower rates. This is important here because Hubbert's analysis is dependent on the finding rate being a function only of the physical resource base and its state of depletion.

* *The procedure used to estimate reserve growth utilizes the average growth rate over many years. However, the year-to-year historical growth rates have tended to be quite volatile, so the average growth rate for a single year or single period of 10* ft of drilling is at best a rough approximation. Furthermore, there are reasons to suspect that the *long-term trend* of reserve growth may now be turning downwards, causing a further error in an estimate assuming an unchanging trend.

## RECONCILING THE DIFFERENT ESTIMATES

Which of these resource assessments are to be believed? in approaching this question, OTA used three criteria:

1. Is there a consensus, or even a "central tendency, " in the scientific community?
2. How credible are the methods used by the assessors, in the abstract and in actual performance?
3. What do the different assessments imply in terms of geology and future discoveries? Are these implications credible?

## Is There A Consensus?

In OTA's judgment, the range of opinion in the scientific community about the size of the natural gas resource is too wide to represent a significant consensus. Not only are there the obvious divisions along the lines of the various estimates, or simply between "optimistic" and "pessimistic, " there is also an important division between scientists who believe in a particular estimate or range of estimates and those who do not believe that the state of knowledge is adequate enough to allow any reliable estimate to be made. Furthermore, some scientists believe that those estimates that invoke current technology and economic relationships—the great majority—are simply irrelevant, whether or not they are correct within the constraints of these assumptions. These scientists believe that both the inexorable advance of technology and rising prices that reflect resource scarcity will constantly push outwards the boundaries of the recoverable resource base. As noted previously, the history of resource estimation in general tends to support this view; cycles of predictions of scarcity followed by radical upward revisions in resource assessments appear to be common for nonrenewable resources (see box E). On the other hand, the USGS

### Box E.—A Very Brief History of Petroleum Exploration

The history of petroleum exploration in general, and exploration for natural gas in particular, has been one of continuous movement toward new discovery horizons and resulting reappraisals of resource potential. The "movement" encompasses new geologic theories and "ideas," new exploration and production technologies, and new geographic areas.

During the first half-century of exploration following Drake's initial discovery in 1859, exploratory drilling was essentially random drilling, drilling at oil seeps, or drilling in areas where previous strikes had been made. Then a succession of geologic insights began to open up new horizons for exploration: first, the understanding that anticlines, some with surface manifestations, could serve as traps for petroleum; then, the discovery that petroleum deposits could exist in traps on the flanks of salt domes; next, the recognition of the petroleum potential of sand lenses and stratigraphic traps; and finally, the insight that petroleum could exist in recoverable quantities *underneath* thrusting plates, leading to the opening up of the Overthrust Belts to exploration and eventual large, discoveries.

Another discovery "horizon" was the growing sophistication of the tools of the trade: the advent of the gravity meter and magnetometer, allowing the locating of geologic anomalies that might signal the existence of structural traps; the addition to the explorer's tool kit of refractive and then reflective seismology, which permitted the detailed mapping of geologic structures; the introduction of rotary drilling and advanced drill bits that allowed deeper horizons to be explored; the growing use of fracturing technologies, which opened up another geologic horizon in petroleum-bearing rock of low permeability; and the engineering triumphs of offshore drilling technologies.

At the same time, exploration and development moved into new regions, sometimes driven by the new technologies (e.g., the continental shelves) or new ideas (e.g., into Texas after realization of the importance of salt domes) and sometimes driven simply by the need for new supplies and dwindling prospects in the mature regions. Thus, exploration began in the Appalachian region but moved inexorably into Ohio and Kansas, into California and the mid-continent region, to the onshore Gulf of Mexico, and spilled out into the Offshore, moved to the Overthrust Belt, and drove to deeper horizons in the Anadarko.

This history of constant movement to new horizons provides grist for the mill of both the resource optimists and the pessimists. The optimists focus on the seemingly continuous ability of explorationists to find new geologic concepts and to develop new technologies that allow them to expand the petroleum resource base over and over again. The pessimists focus on the questions: Just how long can this go on? How many additional places are there to look? As noted earlier in the section on "Resource Base Concepts," this history and the ongoing controversy in the search for petroleum is a paradigm for the development of many nonrenewable resources.

SOURCE Dr. John Schanz, Senior Specialist in Energy Resources Policy, Congressional Research Service.

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oil **and gas resource estimates of the past decade and a half sustained some very substantial downward** revisions as estimation procedures became more sophisticated.

Tables 10 and 11 summarize some of the key arguments used by the optimists and pessimists in explaining their positions on the probable size of the gas resource base. Because each of the arguments has merit, it is obvious that an unambiguous answer to the question, "How large is the U.S. gas resource base?" is not likely. Selection of a "best" estimate is further confused by the observation that some major disagreements exist even among assessors who appear to have the same general outlook (see box F), and some of the more important disagreements occur in areas where considerable geologic data exists to aid the resource assessments (and where, consequently, the **most** agreement might be expected).

**Table 10.—The Optimist's View of Gas Resources**

- **Just a few short years ago nobody had heard about the Overthrust Belt and the Tuscaloosa Trend; now everybody has jumped in. The pessimists have always been wrong about resource shortages.**
- **Increased prices for gas and better exploration techniques have opened up a huge new resource in small fields. Past estimates of the number of small fields relied on data from a time when a small field was likely to be abandoned as a dry hole.**
- **We haven't been looking for natural gas for more than a few decades, so a mature basin for oil—with little prospects for significant new finds—isn't necessarily mature at all for gas. This is especially true because the conditions that led to gas are often hostile to the formation and preservation of oil, and thus the presence of these conditions would have tended to keep explorers away. A key example of this effect is the deep gas resource.**
- **A good part of the lower finding rates of the recent past was due to the substantial increase in low-risk, low-yield drilling. The lower rates therefore do not necessarily imply "resource depletion."**
- **Most resource estimates—including optimistic ones such as those of USGS and PGC—represent only snapshots in time, reflecting current economics and technology. The resource base estimates will tend to grow over time as prices rise and technology advances.**
- **The decline in proved reserves of the past decade, interpreted by many as a sign of resource depletion, actually represents merely a rational response to high discount rates, that is, a reduction in inventory to the minimum amount necessary to sustain production.**
- **Recent price increases have opened up a large potential for new reserves from the growth of older fields. This new gas will come from closer spaced drilling, the extention of fields to lower permeability areas that were previously uneconomic, the lowering of abandonment pressures, and well workovers.**

SOURCE: Office of Technology Assessment

**Table 11.—The Pessimist's View of Gas Resource**

- **We have drilled too many holes in the Lower 48 States and tested too many ideas to believe there is much room for brand new natural gas horizons.**
- **If there's so much gas right here in the Lower 48, why are we testing the limits of hostile environments in the Arctic and continental slopes?**
- **The geologists who make industry's resource estimates tend to be the most successful ones, those who have a built-in bias toward optimism because of their experience.**
- **We have already found most of the "easy," giant fields. The future is in the smaller reservoirs, and there doesn't appear to be enough of these to provide the amount of resources the optimists say is there.**
- **The depletion effects apparent in exploratory drilling finding rates are actually understated because the advance of exploration technology, by increasing the success rate of exploratory drilling, has tended to hide the onset of depletion.**
- **The higher resource estimates, when translated into the number of fields of various sizes that must be *discovered* to yield this much gas, look very shaky when compared to the numbers of these fields that we have actually been discovering lately.**

SOURCE: Office of Technology Assessment.

Given what OTA would term a lack of consensus, is there at least a "central tendency?" What is an acceptable range of estimates for the size of the recoverable resource base that excludes "unconventional gas"* and gas that cannot be exploited profitably at gas prices in the same range as today's and with technology that is well within reach in the next few decades? OTA believes that a substantial majority of scientists concerned about the gas resource base would feel comfortable **somewhere within**** a range that included Nehring's estimate as the extremely pessimistic minimum and the PGC estimate as not quite the maximum, but close to it. This range is about 280 to 915 TCF for the remaining conventional gas resource (including proved reserves and the growth of known fields) recoverable, with readily foreseeable technology and given today's economics, for the Lower 48 States.

*Gas from very tight formations, geopressurized zones, coal beds, and Devonian shales. However, gas that arguably could be placed in these categories but that is commonly produced today, would be considered conventional.

**Many wou Id no doubt disagree strongly with values near one extreme or the other, however.

### Box F.—Are the USGS and PGC Gas Resource Assessments Really Similar?

Two widely referenced gas resource assessments—those of the USGS and the Potential Gas Committee—have similar estimates for the ultimately recoverable gas in the Lower 48 (1,400 TCF and 1,542 TCF, respectively) and are often used to illustrate what some feel is a wide consensus for an optimistic gas future. Are these two assessments really so similar? The table below compares the regional assessments of undiscovered gas from both groups,* based on the PGC reporting areas.

| | Onshore | | Offshore | |
|---|---|---|---|---|
| *PGC reporting area* | *PGC* | *USGS* | *PGC* | *USGS* |
| A | 41 | 11 | 16 | 24 |
| B | 13 | 21 | 30 | 3 |
| C | 3 | 6 | | |
| D | 39 | 24 | | |
| E&G | 34 | 101 | 52 | 69 |
| H | 159 | 124 | | |
| I | 4 | 8 | | |
| J-N | 99 | 43 | | |
| J-S | 34 | 33 | | |
| L | 16 | 19 | 18 | 7 |
| Total** | 442 | 390 | 116 | 102 |

The table shows some substantial disagreements about where the major undiscovered gas resources lie, but it also shows that, on the average, the region-by-region assessments agree quite well.

Important areas where the two agencies differ are:

- J-N—the midcontinent region (Kansas, Oklahoma, parts of Texas), where PGC is far more optimistic about deep gas.
- E&G onshore—the gulf coast
- A—the Eastern Appalachian States
- B offshore—Mississippi, Alabama, and Florida, where PGC remains optimistic about gas in the eastern Gulf of Mexico.
- D—Arkansas, north Louisiana, and central Texas.

The average level of agreement can be checked by conducting a linear regression of the two data sets. This yields a correlation coefficient of 0.74, which is a good agreement for two resource assessments conducted somewhat independently of each other.*** Also, removing the two worst disagreements—the offshore gulf coast and mid-continent estimates—increases the correlation coefficient to 0.92, a high value.

Consequently, the differences in no way "discredit" either of these assessments. The differences do illustrate, however, the substantial disagreements that can exist between two groups considered optimistic, and thus they illustrate the considerable uncertainty associated with these resource assessments.

*The PGC values exclude "probable" resources, which include new pools in discovered fields. Strictly speaking, PGC defines these pools as undiscovered; USGS does not, and includes them in its "inferred reserves" category.

**Excludes cumulative production, proved reserves, and growth of known fields.

***The estimators have too much access to the same studies and estimates, and to each other, to allow a claim of strict independence between the two assessments.

OTA believes that the minority who might like the range extended would consist mainly of those who believe that the upper end should be higher. Furthermore, OTA suspects that a thorough review of the production implications of the **lower** end of the range—as discussed in the next chapter—would tend to push many scientists away from this end of the range. * It should be added, however, that some of those who are considerably less optimistic than PGC, and even USGS, —

*As shown in chapter 5, a 280-TCF remaining resource implies that the year 2000 production of Lower 48 conventional gas, recoverable with existing or foreseeable technology and at the current cost/price relationships, cannot be much greater than 4 TCF/yr.

are major oil and gas producers—e.g., Exxon**— who are very familiar with most of the areas that are supposed to supply the United States with the "optimistic" levels of new gas discoveries.

## How Credible Are the Methods?

How credible the methods are is generally difficult to determine because few resource assessments using geologic approaches reveal many details of their assessment processes. Generally, more details are available for the assessments based on historical, extrapolative approaches; in addition, USGS makes available to the public its open-file reports and data. OTA did not attempt to review the extensive USGS backup information because of time and budget constraints. Historical approaches have been reviewed in a number of reports,[26] and for the most part OTA chose to use these reports instead of conducting a totally independent review.

In general, OTA is skeptical of historical approaches to resource assessment when they are based on national data and when they are the sole means of estimation. The substantial data problems associated with natural gas exploration (especially during those years when gas was valued as little more than a byproduct of oil production), the broad range of activity covered by any single data series, and the distorting effects of Government controls are important sources of this skepticism.

The most important estimate based strictly on a historical approach is Hubbert's, because he has gained substantial credibility from his successful predictions of declining U.S. oil production. As discussed earlier in this chapter, OTA notes substantial problems with Hubbert's approach and believes that his extremely pessimistic estimate (870 TCF) of ultimately recoverable conventional gas is too low.

Of the assessments using geologic approaches, only the assessments of USGS and PGC are reviewable in any sense because details of the others are not public information. In OTA's opinion, both assessment processes are serious attempts to wrestle with a most difficult problem. One problem with both assessments is the failure to include the detailed assumptions behind, and implications of, the assessment, thus precluding much opportunity for useful feedback from those outside the assessment process. The USGS assessment may also be hampered by lack of access to proprietary industry data; PGC, on the other hand, apparently has access to excellent data but appears to ignore the insight that might be gained from analyses of discovery trends (i.e., the historic approach),

## Are the Physical Implications of the Assessments Plausible?

Most gas resource assessments do not provide descriptions of either the direct physical implications of their resource estimates (e.g., the number and size of fields implied by the estimate) or, conversely, the initial physical model used to derive the estimate. Nevertheless, some physical implications can be drawn directly from the estimates. This is especially true when the estimates are separated into components: onshore and offshore (quite common), deep and shallow (e.g., the PGC assessment), and individual regions or even smaller provinces (USGS divides the United States into 137 separate provinces). Consequently, it is clear that PGC believes that the deep resource below 15,000 ft represents a massive source; fully 39 percent of the onshore undiscovered resource of the Lower 48 States is projected to be deep gas. In a similar vein, USGS clearly appears to have given up on the eastern Gulf of Mexico but has great hope–as does PGC–for another "frontier" area, the Western Overthrust Belt.

Rather than carrying out a detailed "translation" of each assessment, OTA chose to examine two basic physical issues that appear to cut across virtually all of the assessments. These issues, as stated by Nehring,[27] are:

- Does the assessment imply a substantial break with past and recent discovery trends and patterns?

**OTA has been told informally by Exxon geologists that Exxon's most recent internal estimates of the U.S. gas resource base are considerably below those of USGS and PGC. The major disagreements are with estimates for the Lower 48 onshore gas potential.

26 For example, Wiorkowski, op. cit.

27 R. Nehring, *The Discovery of Significant Oil and Gas Fields in the United States*, op. cit.

- If the assessment does imply such a break, what is the explanation for it? IS it credible?

## A Break With Past Trends?*

The most obvious ties between past trends and the magnitude of the resource base are the analyses performed in the "historic approaches" to resource assessment. In general, these approaches have given relatively pessimistic results when used with U.S. gas production and exploration data. For example, all four of the estimates using pure data-tracking techniques (two by Hubbert, one each by Wiorkowsky and Bromberg/Hartigan) in table 6 are below the USGS estimate, with three of the four at least 400 TCF below. In addition, the RAND estimate, which is at least partly dependent on past discovery trends, is nearly 500 TCF below the USGS estimates.

This series of pessimistic resource estimates based on trend analysis, when coupled with the very low rates of reserve additions in the Lower 48 States from 1968 to 1978 (average yearly AGA reserve additions were 9.6 TCF v. average production of 20.6 TCF/yr), represent a strong initial argument that the more optimistic resource estimates do represent a break with past trends, while the pessimistic estimates do not. However, as noted in the discussion of historical approaches to resource assessment, the available data used to measure trends in exploratory success (or trends in other factors that may be used to form judgments about the probable size of the resource base) tend to measure multiple rather than single processes; for example, measures of the success of drilling for new fields are, in fact, measuring a range of activities from the high-risk testing of new geological ideas to the low-risk redrilling of formerly uneconomic dry holes. Consequently, none of these trends can be interpreted in an unambiguous manner. The discussions in chapter 5 about the factors that affect the various components of reserve additions give a sense of the complexity of individual trends and of the difficulties in interpreting the trends.

Trends in the discovery of new fields appear likely to be most closely associated with the remaining recoverable resource base; these trends are examined in the following paragraphs.

Table 12 displays the returns to new field wildcat drilling in the onshore Lower 48 States from 1966 to 1981, The patterns displayed in the table demand careful deciphering. The gas volumes found per successful gas new field wildcat

*Readers interested in past trends in petroleum exploration may also wish to read *Exploration for Oil and Gas in the United States: An Analysis of Trends and Opportunity,* by John J. Schanz, Jr. and Joseph P. Riva, jr., of the Congressional Research Service (CRS report No. 82-138 S, Sept. 16, 1982).

**Table 12.—Returns to New Field Wildcat Drilling in the Onshore Lower 48 States, 1966-81 (BCF/well)**

| Year | New field discoveries | | | Percent of new field discovery wells that find gas |
|---|---|---|---|---|
| | Per all NFWs | Per new field discovery well | Per new gasfield discovery well | |
| 1966 | 0.46 | 4.56 | 18.56 | 25 |
| 1967 | 0.42 | 3.96 | 11.93 | 33 |
| 1988 | 0.24 | 2.66 | 10.25 | 27 |
| 1989 | 0.24 | 2.66 | 7.47 | 36 |
| 1970 | 0.29 | 3.01 | 8.20 | 37 |
| 1971 | 0.16 | 1.67 | 3.70 | 45 |
| 1972 | 0.24 | 2.11 | 4.46 | 47 |
| 1973 | 0.34 | 2.30 | 3.89 | 59 |
| 1974 | 0.24 | 1.60 | 2.88 | 56 |
| 1975 | 0.22 | 1.47 | 2.91 | 51 |
| 1976 | 0.18 | 1,02 | 1.85 | 55 |
| 1977 | 0.20 (.32)[a] | 1.15 (1 .86) | 2.23 (3.61) | 52 |
| 1978 | 0.17 (0.36) | 1.07 (2.27) | 1.96 (4.17) | 55 |
| 1979 | 0.20 (0.26) | 1.07 (1 .40) | 1.85 (2.48) | 58 |
| 1980 | (0,27) | (1.37) | (2.69) | 51 |
| 1981 | (0.34) | (1.88) | (3.95) | 48 |

[a]AGA data (EIA data).

SOURCE: R Nehring, "Problems in Natural Gas Reserve, Drilling, and Discovery Date," contractor report to the Off Ice of Technology Assessment, 1983 show a startling decline during the period, from 18.56 billion cubic feet (BCF) per well in 1966 to 1.85 BCF per well in 1979 (use of EIA data moderates this trend somewhat, but the EIA and AGA data are not strictly comparable). This means that the average field size found by a successful gas wildcat declined by a factor of 10 during 1966-79.

Because the larger fields in a basin are generally found early in the discovery process, a sharply declining average field size is often interpreted as a sign that the discovery cycle is winding down. However, the data shown in the table are collected from multiple basins, and during the time period in question, the pattern of gas exploration may have been influenced by increased gas prices and other factors. For example, it is widely believed that deliberate exploration for small gas targets (e. g., in areas where past exploration identified then-uneconomic gas deposits) increased sharply during this period. Such an increase in the willingness of explorationists to go after small targets would tend to reduce field size averages **even if high-risk exploration for large fields maintained a steady success record. Consequently, the decline** in average field size may not fairly represent the actual condition of the resource base.

The record of returns to wildcat drilling **per well drilled tends to support this** view. These returns per well drilled have exhibited only a slight decline since 1968; the success rate, which varies from a low of 2.3 percent in 1968 to a high of 10.8 percent in 1979, essentially compensates for the declining field size. In other words, **while each gas wildcat well completed returned far less gas in** 1979 **than in 1966, the actual number of wildcat wells drilled to find each trillion cubic feet of gas did not increase very much during this period.** This relatively optimistic result should be tempered, however, by the observation that the percentage of wildcats aimed deliberately at gas targets probably increased during this period. Consequently, it is likely that the actual gas-directed effort-as distinct from the total petroleum-directed effort–that was needed to find a unit of gas probably did increase during the period.

Although the data in table 12 look more optimistic than might have been initially expected, the history of natural gas development implies that, in order to sustain successful levels of reserve additions for the long-term, efforts must be made to open new geologic horizons and find the large fields that are the cornerstone of reserve growth in later years. Consequently, it is useful to examine the pattern of discovery of different-sized fields.

The American Association of Petroleum Geologists (AAPG) publishes the primary public record of the discovery of petroleum fields by size and discovery year, and this record may be used to examine patterns of discovery. The record must be used cautiously, however, because AAPG appears to have undercounted the number of fields discovered. * For example, from 1971 to 1975, AAPG reports only 49 gas discoveries of a size greater than 60 BCF. In comparison, the RAND data base reports 141 fields in this size range during the same time period.[28] Consequently, the AAPG data should be examined for trends rather than absolute magnitude, and even the trends may be skewed if undercounting and other problems were not consistent over time.

Table 13 presents the historical record of new gas field discoveries by field size, for 1945-75, as compiled by AAPG. * * In parallel with the trends shown in table 12, the percent of significant (size class A through D) gas fields in all gas discoveries decreased over the 30-year period, while the effort required to find a significant field increased through the 1960s but then declined to earlier levels.

'The data in the table can be used to examine the discovery trends of larger fields. Figures 11 and 12 show trends in, respectively, the number

*Part of this problem may arise from simple disagreements over field boundaries; the EIA data base, for example, treats the Hugoton field as three separate large fields, whereas other analysts might count it as one. Also, field reserve estimates are not consistent across data bases.

[28]R. Nehring, *Problems in Natural Gas Reserve, Drilling, and Discovery Data,* contractor report to OTA, 1983.

* +! The record stops in 1975 because AAPG classifies fields as gas or oil fields only after the passage of 6 years past the discovery report.

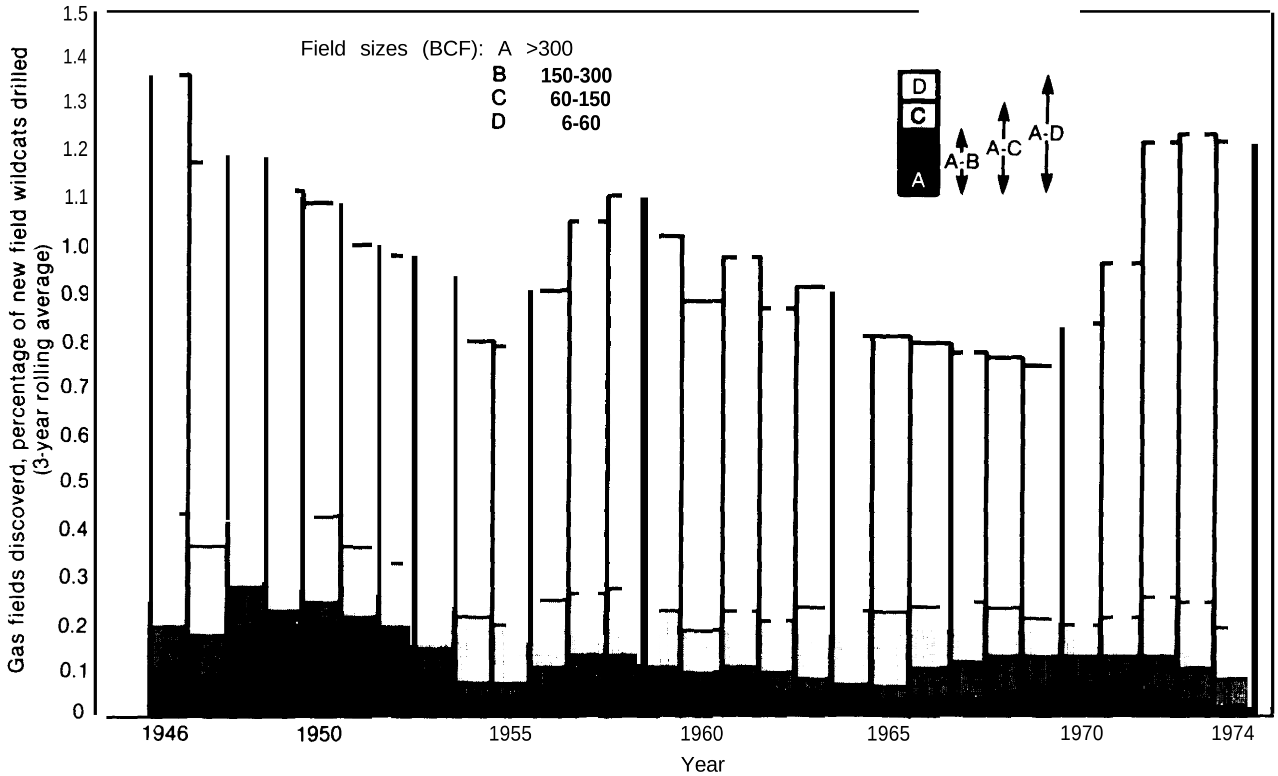
**Table 13.—Historical Record: Number of New Gasfield Discoveries Proved After Six Years To Be of Significant Size**

| Year drilled | Total wells reported as gas wells at end of year of completion | Number of fields in each size classification[a] after 6 years development history: A | B (Significant) | C (Significant) | D | E | F | Total | Total significant size gasfields: A-D Inclusive (A+B+C+D) | Percent of significant gasfields in all gas discoveries | Total new field wildcats drilled | Percent of significant gas finds in total new field wildcats drilled |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1945 | 103 | 3 | 2 | 11 | 33 | 24 | 20 | 93 | 49 | 52.69 | 2,905 | 1.69 |
| 1946 | 78 | 1 | 2 | 7 | 22 | 29 | 12 | 73 | 32 | 43.84 | 2,995 | 1.07 |
| 1947 | 106 | 5 | 5 | 4 | 30 | 35 | 19 | 98 | 44 | 44.90 | 3,325 | 1.32 |
| 1948 | 116 | 3 | 3 | 7 | 33 | 35 | 19 | 100 | 46 | 46.00 | 4,087 | 1.13 |
| 1949 | 121 | 8 | 7 | 8 | 34 | 43 | 12 | 112 | 57 | 50.89 | 4,238 | 1.34 |
| 1950 | 118 | 4 | 4 | 8 | 28 | 44 | 19 | 107 | 44 | 41.12 | 5,149 | 0.85 |
| 1951 | 155 | 10 | 4 | 10 | 41 | 57 | 16 | 138 | 65 | 47.10 | 6,044 | 1.08 |
| 1952 | 171 | 10 | 7 | 7 | 44 | 65 | 15 | 148 | 48 | 45.95 | 6,440 | 1.06 |
| 1953 | 177 | 3 | 3 | 6 | 40 | 89 | 18 | 159 | 52 | 32.70 | 6,634 | 0.78 |
| 1954 | 248 | 4 | 1 | 12 | 51 | 104 | 39 | 211 | 68 | 32.23 | 7,033 | 0.97 |
| 1955 | 228 | 2 | 3 | 11 | 33 | 107 | 43 | 199 | 49 | 24.62 | 7,743 | 0.63 |
| 1956 | 230 | 2 | 4 | 5 | 52 | 92 | 26 | 181 | 63 | 34.81 | 8,436 | 0.75 |
| 1957 | 247 | 9 | 5 | 15 | 70 | 105 | 30 | 234 | 99 | 42.31 | 7,556 | 1.31 |
| 1958 | 262 | 3 | 6 | 9 | 55 | 143 | 25 | 241 | 73 | 39.29 | 6,618 | 1.10 |
| 1959 | 308 | 4 | 1 | 6 | 51 | 135 | 28 | 225 | 62 | 20.13 | 7,031 | 0.88 |
| 1960 | 240 | 6 | 2 | 9 | 63 | 135 | 22 | 237 | 80 | 33.76 | 7,320 | 1.09 |
| 1961 | 316 | 4 | 3 | 4 | 35 | 156 | 40 | 242 | 46 | 18.59 | 6,909 | 0.66 |
| 1962 | 317 | 3 | 4 | 11 | 61 | 161 | 52 | 292 | 79 | 27.05 | 6,794 | 1.16 |
| 1963 | 240 | 4 | 1 | 7 | 38 | 124 | 41 | 215 | 50 | 23.26 | 6,570 | 0.76 |
| 1964 | 252 | 4 | 1 | 11 | 37 | 136 | 37 | 226 | 53 | 23.45 | 6,623 | 0.80 |
| 1965 | 234 | 1 | 3 | 10 | 38 | 142 | 30 | 224 | 52 | 23.21 | 6,175 | 0.84 |
| 1966 | 232 | 1 | 3 | 7 | 36 | 142 | 12 | 201 | 47 | 23.38 | 6,158 | 0.76 |
| 1967 | 179 | 4 | 5 | 6 | 26 | 111 | 12 | 164 | 41 | 25.00 | 5,271 | 0.78 |
| 1968 | 126 | 1 | 5 | 7 | 27 | 83 | 14 | 137 | 40 | 29.20 | 5,205 | 0.77 |
| 1969 | 190 | 3 | 2 | 4 | 35 | 116 | 14 | 174 | 44 | 25.28 | 5,956 | 0.74 |
| 1970 | 184 | 5 | 4 | 3 | 25 | 79 | 14 | 130 | 37 | 28.46 | 5,069 | 0.72 |
| 1971 | 202 | 2 | 3 | 3 | 38 | 102 | 12 | 160 | 46 | 28.75 | 4,463 | 1.03 |
| 1972 | 273 | 3 | 2 | 6 | 47 | 187 | 0 | 245 | 58 | 23.67 | 5,086 | 1.14 |
| 1973 | 416 | 2 | 6 | 10 | 57 | 284 | 0 | 359 | 75 | 20.89 | 4,989 | 1.50 |
| 1974 | 445 | 0 | 2 | 6 | 51 | 329 | 0 | 388 | 59 | 15.21 | 5,652 | 1.04 |
| 1975 | 448 | 3 | 0 | 1 | 64 | 336 | 0 | 404 | 68 | 16.83 | 6,104 | 1.11 |

[a]Size classifications: A = >300 BCF
B = 150-300 BCF
C = 60-150 BCF
D = 6-60 BCF
E = <6 BCF
F = noncommercial

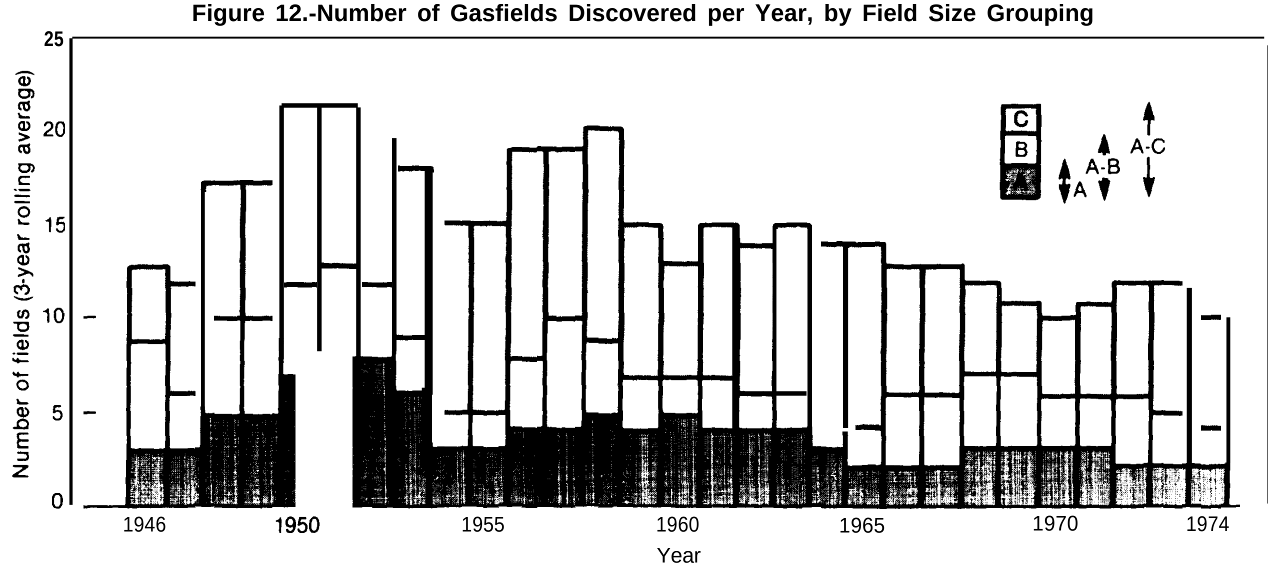
SOURCE: R. R. Johnston, "North American Drilling Activity in 1981," *AAPG Bulletin*, vol. 66/ November 1982.

**Figure 11.–Number of Gasfields Discovered As a Percentage of New Field Wildcats Drilled, by Field Size Grouping**




SOURCE: Office of Technology Assessment, based on data from table 16 in R. R. Johnston, "North American Drilling Activity in 1961," *AAPG Bulletin,* vol. 66/1 1, November 1982.

**Figure 12.-Number of Gasfields Discovered per Year, by Field Size Grouping**




SOURCE: Office of Technology Assessment, based on data from table 16 in R. R. Johnston, "North American Drilling Activity in 1981 ," *AAPG Bulletin,* vol. 66/11, November 1982.

of fields discovered as a percentage of new field wildcats drilled, and the number of fields discovered per year. Figure 11 shows that the apparent effort (in wells drilled)* required to find fields of size C or larger, B or larger, and A grew sharply during the early 1950s but then leveled off between 1955 **and 1975.** However, these trends would look considerably more pessimistic if "total footage" rather than "wells drilled" were the measure of effort. This is because the average depth of new field wildcats grew steadily during this period, from 4,007 ft in 1946 to 6,071 ft in 1975.[29]

Figure 12 shows that, starting about 1950, the number of moderate-to-large gas fields declined steadily through 1975. These larger fields may be particularly important for continued reserve additions because of the general belief that the larger fields generate the majority of field growth (from extensions, new pool discoveries, and revisions).

The impression gained from table 13 and figures 11 and 12–that finding rates for the small-to-moderate sized fields have held up very well and even increased, but that rates of finding the larger fields have declined somewhat over the past few decades—is reinforced by an examination of Lower 48 gas field discoveries of 1 TCF and larger. Such discoveries were scattered throughout the 1916 through 1966 period, with particularly large discoveries** in 1916 (Monroe, LA, 9 TCF), 1918 (Hugoton, KS/TX/OK, 36 TCF and Panhandle, TX, 31 TCF), 1921 (San Juan, NM, 18 TCF), 1928 (Jalmat, NM, 6 TCF), 1934 (Katy, TX, 7 TCF), 1936 (Carthage, TX, 6 TCF), and 1952 (Puckett, TX, 4 TCF).[30] However, according to the 1977 International Petroleum Encyclopedia,[31] no gas fields larger than 4 TCF were found between **1953** and 1967, and no gas fields larger than 1 TCF were found between 1967 and 1975.***

The trends in discovery up to the mid-1970s, although rendered somewhat ambiguous by the nature of the data, appear to support two conclusions. First, they show that exploration trends for gas have not nearly been as much a cause for pessimism as have oil exploration trends; in short, they do not show why the resource pessimists such as Hubbert predict such a radical drop in new discoveries. The rate of discovery of significant fields (fields of sizes A through D) did not experience the kind of steep decline that would seem to be a prerequisite for predicting—as the Hubbert resource estimate does–that undiscovered resources now total only 100 TCF. Second, the trends indicate that the type of fields usually associated with opening up major new horizons were not being discovered and that more and more of the new fields appeared to be coming from further along in the discovery cycle. The limited number of giant fields discovered in this period gives some cause to question the relatively optimistic estimates of USGS and PGC.

As to recent trends, the recent upsurge in total reserve additions has been the common centerpiece in arguments that the "resource optimists" have been right all along. Questions are raised about whether recent large discoveries in the deep Anadarko Basin and in the Overthrust Belt signify a reversal of the long-term, more pessimistic trends.

In OTA's opinion, responsibility for the reserve additions of the past few years—and therefore the implications for **future** reserve additions and production–cannot be assigned to a particular cause without a detailed investigation, at the level of individual fields and entrepreneurs, of the precise nature of the increases. Such an investigation would attempt to determine whether the new reserve additions represent a true turnaround in the exploratory process or a one-time surge of reserve development caused by the sudden movement from the subeconomic into the

* "Apparent" because some of the wells were aimed deliberately at small targets and should not be included in the "effort" involved in finding large fields. As noted, however, there is no way to separate data about these wells from the overall data.

[29] R. R, Johnston, "North American Drilling Activity in 1981," *AAPG Bulletin*, vol 66/11, November 1982.

** Some of these fields—Hugoton, Panhandle, San Juan—are considered multiple fields by some analysts, one field by others. Also, there is considerable variation in reserve estimates from one source to another.

[30] Oil and Gas Resources Data System, Energy Information Administration; and J. McCaslin (ed.), *International Petroleum Encyclopedia, vol. 10* [Tulsa, Okla.: Petroleum Publishing Co., 1977).

[31] McCaslin, op, cit.

*** It is possible, however, that further growth of fields that were below the 1 TCF level in 1977 could have moved them into the "greater than 1 TCF" category in later years.

economic range of a limited inventory of known prospects and an acceleration of the normal pace of field development. OTA has not seen any convincing analyses arguing one side or the other.

As for the Overthrust Belt and Anadarko, the future of these areas is uncertain. The Overthrust Belt did produce some very large new fields in the late 1970s (the Whitney Canyon/Carter Creek and East Anschutz Ranch fields appear to have resources greater than 1 TCF) and its potential is substantial. However, despite continued searching, no new giant fields have been discovered in the past few years. **In the Anadarko, the recent declines** in prices for deep gas may have moved some gas from "economic" to "subeconomic, ' although the earlier superheated market for this gas and the resulting distortions in prices and production costs make it difficult to predict where the economic/subeconomic boundary might lie in the future. Also, recent engineering difficulties and rapid pressure declines in some fields imply that some overestimates may have been made in calculating reserves and estimating resources.

In conclusion, in OTA's opinion **the gas discovery trends of the past several decades, while not supporting the most pessimistic of the recent gas resource estimates, also do not support the relatively optimistic estimates of PGC and, possibly, USGS.**

## Some Alternative Explanations

The (until recently) moderately pessimistic discovery trends and optimistic resource base estimates can be reconciled by two possible arguments:

- It is not the resource base but the market distortions caused by Government regulations that have caused discovery trends to be disappointing. Exploratory incentives have been skewed toward low-risk, low-payoff gas prospects.
- The historical trends do represent the depletion of traditional sources of natural gas. Now, however, improved technology and higher prices will allow explorers to find large quantities of gas from:
  —small fields;
  —reworking of older fields;
  —new frontiers, including deep gas; and
  —subtle stratigraphic traps.

### The Causes of Past Trends

Is it the **nature of the remaining resource base** that has been the primary influence on historical declining trends in new field discoveries, or was it instead the **economic and regulatory environment** that provided the controlling influence? Does the relatively low rate of discovery of large new gasfields during the last decade and a half reflect resource depletion, or are these rates an artifact of the erratic price and regulatory history of natural gas? If gas resources are substantially depleted, it appears unlikely that gas finding rates and discoveries of large new fields will rebound to levels that would sustain high production rates. If the economic/regulatory history of gas is the cause, then optimism about future production potential may be well founded, assuming that economic and regulatory conditions can be made favorable to the gas discovery process.

The basic argument that low finding rates for new fields and other warning signals do **not** reflect resource depletion centers around the idea that the rigid price controls of the period before passage of the Natural Gas Policy Act of 1978 (NGPA) locked drilling into lower cost and risk areas that do not coincide with where the major gas potential resides. The "culprit" for this is said to be the method used by the old Federal Power Commission (FPC) to calculate allowable "area" and "national" gas prices. FPC assumed that future exploratory and development costs would be similar to past average costs, and by basing the allowable price on this assumption, essentially **guaranteed** that drilling would be confined to areas where costs were expected to be low.

A past proponent of this view has been the American Gas Association. AGA has conducted a series of studies[32] comparing total gas well completions to estimates of gas resource potential* in the Outer Continental Shelf, Alaska, the

[32] The latest is AGA, "Gas Well Drilling Activity and Expenditures in Relation to Potential Resources, " *Gas Energy Review, vol.* 9, No. 1, January 1981.

*The measure used for "Resource Potential" was PGC's estimates of potential supply.

shallow Lower 48 area, and deep (below 15,000 ft) horizons. Its September 1979 analysis, which includes drilling data through 1977, concludes that "the drilling data suggested that the decline in proved reserves was not due to a depletion of gas sources but rather to a lack of economic incentives for drilling under an artificially constrained, regulated environment [emphasis added]."[33] This conclusion was based on the poor correlation of gas well completions to gas resource potential detected in the study* (see the first two circle charts in fig. 13). However, a more recent (January 1981 ) analysis added a comparison of gas well expenditures to gas resource potential (third circle chart in fig. 13). Noticing a good correlation of expenditures to resource potential,** AGA omitted the earlier conclusion and attributed the imbalance between drilling and potential to "the much lower cost-per-well and cost-per-foot figures for the shallow, Lower 48 wells. "[34] The very high drilling costs and risks of the high gas potential frontier areas necessitate a very cautious attitude toward drilling, whereas the lower costs in developed onshore areas encourage closely spaced development drilling and exploratory drilling for small reservoirs and other marginal targets.

A corollary to the argument about the effects of low allowable gas prices is used to explain why the sharp price increases of the past several years have not improved the rate of new field discoveries. According to this view, drilling priorities will not immediately be corrected by rising prices because the long period of controls has created a large backlog of low-risk, previously marginal exploration prospects that are now commercially viable. Until this backlog is reduced, the argument goes, exploratory drilling will stay away from the high-risk, high-payoff wells that could find the large fields[35] that now only appear to be scarce. Furthermore, because price increases expand the boundaries of the "economically recoverable" resource base and thus add to the inventory of low-risk prospects, it is claimed that the trend toward low-risk, low-payoff drilling is likely to continue if prices continue rising.[36]

[33] AGA, "Drilling Activity and Potential Gas Resources, " *Gas Energy Review, vol. 7, No. 11,* September 1979.

*Of course, an alternate reason for the poor correlation could be that gas entrepreneurs do not agree with AGA's view about where the resource potential lies.

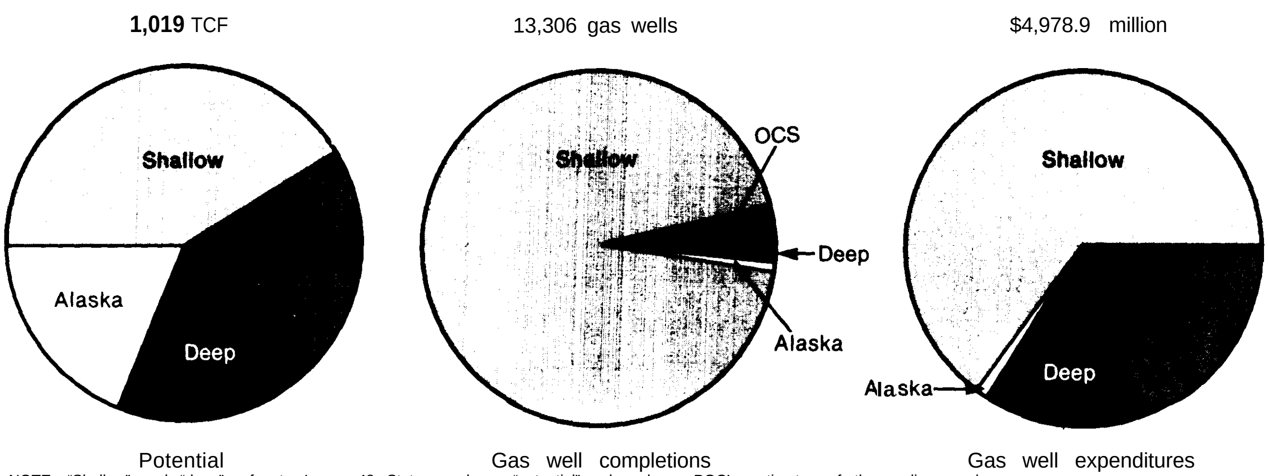
* *Except for Alaska, where lack of a transportation system blocks gasfield development.

[34] AGA, "Gas Well Drilling and Expenditures. . . ," op. cit.

[35] Jensen Associates, Inc., "Early Effects of the Natural Gas Policy Act of 1978 on U.S. Gas Supply, " report to the Office of Oil and Natural Gas, U.S. DOE, April 1981.

[36] R.p O'Neill, "Issues in Forecasting Conventional Oil and Gas Prod uction, " in *Oil and Gas Supply Modeling,* National Bureau of Standards Special Publication 631, May 1982.

**Figure 13.—Gas Potential, Gas Well Completions, and Expenditures—1978**




NOTE: "Shallow" and "deep" refer to Lower 48 States onshore; "potential" is based on PGC's estimates of the undiscovered gas resource

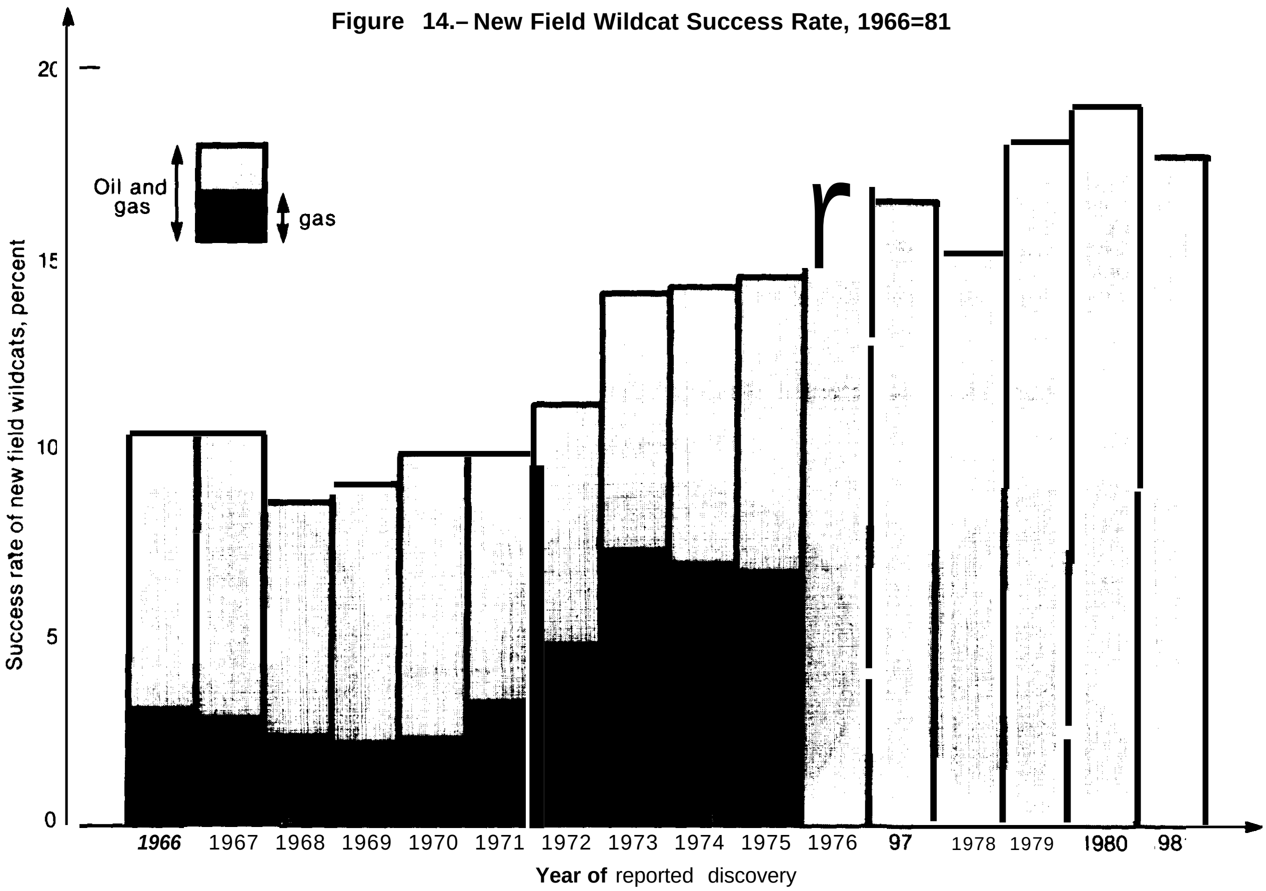
SOURCE "Gas Well Drilling Activity and Expenditures in Relation to Potential Resource," in Gas *Energy Review,* vol *9, No.* 1 (Arlington, Va.. American Gas Association, January 1981).

High-risk, high-payoff drilling may be expected to yield low success rates. Consequently, the sharply improved success ratios of both total exploratory drilling and new field wildcat drilling during the past decade and a half, shown in table 14 and figure 14, has been used to support the thesis that drilling is skewed toward the low-risk targets. The overall success rate of these drilling categories may be affected by a variety of factors, however, that cannot be separated out. For example, substantial progress in improving exploration techniques and computer technology during this period undoubtedly acted to increase success rates, but to an unknown degree. * Also, the success rate is automatically elevated by the decrease in minimum acceptable field sizes and the gas flow rates associated with increased gas prices; small fields and low-permeability reservoirs that in the past would have been considered "dry" are now being developed as producers. Therefore, it is quite conceivable that an increase in **overall** success rates could be accompanied by an increase in high-risk drilling if the other factors affecting success rate were strong enough to overcome the negative effects of the shift in risk,

In addition to arguments about the effects of price controls, some analysts point out that maintenance of high levels of proved reserves in relationship to production would not be compatible with good business practices. According to this argument, high interest rates made it sensible for

*The extensive investigation of the effects of new technology by the National Petroleum Council in 1965 could find no credible quantitative measurement of these effects.

**Figure 14.–New Field Wildcat Success Rate, 1966=81**




NOTE: Gas success rate data not available after 1975 because gasfields and oilfields are separated out only after a 6-year review by AAPG.

SOURCE: Office of Technology Assessment, based on data from American Petroleum Institute, Quarterly Review of Drilling Statistics

**Table 14.-Oil and Gas Drilling Success Rates (discoveries as a percentage of exploratory drilling effort)**

| | Exploratory wells | | | "Wildcats" | | |
|---|---|---|---|---|---|---|
| Year | Completed | Total | Rate | Completed | Total | Rate |
| 1966 | 1,894 | 10,313 | 18.40/o | 635 | 6,158 | 10.3 "/0 |
| 1967 | 1,518 | 8,878 | 17.1 | 544 | 5,271 | 10.3 |
| 1968 | 1,440 | 8,879 | 16.2 | 442 | 5,205 | 8.5 |
| 1989 | 1,700 | 9,701 | 17.5 | 535 | 5,956 | 9.0 |
| 1970 | 1,271 | 7,693 | 16.5 | 493 | 5,069 | 9.7 |
| 1971 | 1,088 | 6,922 | 15.7 | 436 | 4,463 | 9.7 |
| 1972 | 1,285 | 7,539 | 17.0 | 566 | 5,086 | 11.1 |
| 1973 | 1,519 | 7,466 | 20.3 | 701 | 4,989 | 14.1 |
| 1974 | 2,009 | 8,619 | 23.3 | 805 | 5,652 | 14.2 |
| 1975 | 2,143 | 9,214 | 23.3 | 876 | 6,104 | 14.4 |
| 1976 | 2,449 | 9,234 | 26.5 | 986 | 5,840 | 16.9 |
| 1977 | 2,686 | 9,961 | 27.0 | 1,004 | 6,101 | 16.5 |
| 1978 | 2,728 | 10,677 | 25.6 | 983 | 6,505 | 15.1 |
| 1979 | 3,024 | 10,484 | 28.8 | 1,162 | 6,413 | 18.1 |
| 1980 | 3,574 | 11,916 | 30.0 | 1,340 | 7,034 | 19.0 |
| 1981 | 4,585 | 15,168 | 30.2 | 1,423 | 8,052 | 17.7 |
| 1982 | 4,847 | 16,470 | 29.4 | 1,400 | 7,912 | 17.7 |

SOURCE' American Petroleum Institute, "Quarterly Review of Drilling Statistics"

gas producers to reduce their standing inventory—i.e., proved reserves—by maximizing deliverability and reducing exploration. Consequently, from the drilling low point of 1971 to 1982, developmental drilling rose by a factor of 3.66 (18,929 wells drilled v. 69,330), whereas total exploratory drilling rose by only a factor of 2.38 and new field wildcats rose by only 1.77.[37] Carrying this argument further the economic incentive to increase reserves will occur only when the cost of reducing R/P ratios—of adding to the deliverability occurrent reserves–outweighs the cost of adding new reserves.

Although the argument about the lack of an economic incentive to increase reserves is a fair one, it does not take into account the incentive for exploration provided by a number of factors, including the perception in the industry that the rapid declines in reserve levels were dangerous and should be halted if possible, the continued profitability of most larger gasfields even at low prices, and the former inseparability of gas and oil exploration, which allowed gas discovery to benefit from exploration incentives provided by oi l.

The argument about the real cause of the downward trends of past decades is difficult to resolve because the opposing sides are generally arguing less about the data themselves than about their **interpretation.** Both sides agree, for example, that onshore gas exploration has become increasingly oriented to prospects with less "dry hole" risk but with smaller reservoirs with poorer producing characteristics. Those arguing for resource depletion believe, however, that this trend has occurred primarily because **that is the nature of the remaining resource base; those arguing** for a more optimistic view of resources argue that the trend reflects a natural market response to early controlled prices, recent price increases, and high discount rates that favor production over inventory. Undoubtedly, both arguments are valid to some degree; the problem is in determining the relative importance of each.

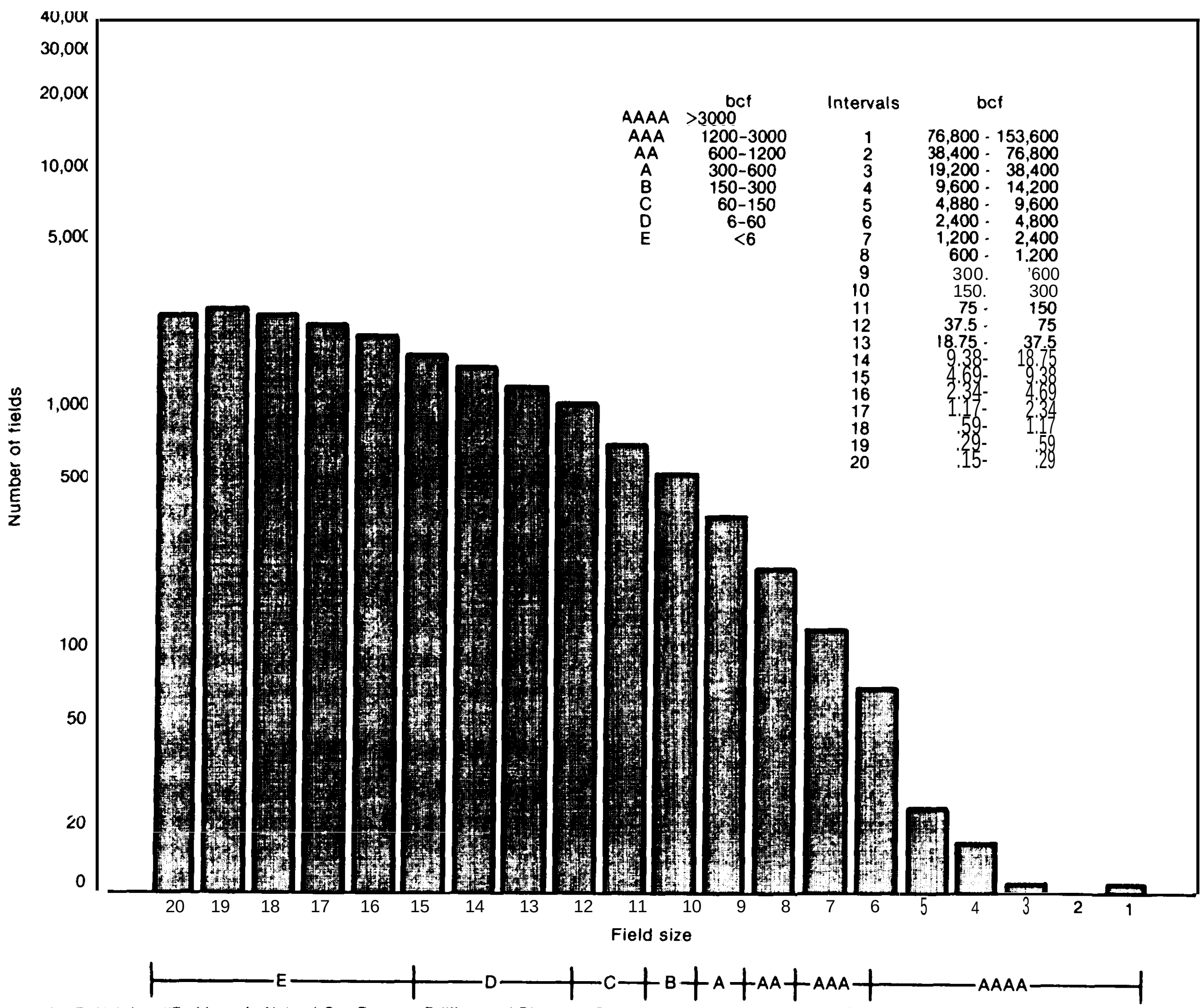
### Potential Major Sources of Additional Gas

**Small Fields.–One** basic argument revolves around the question of whether or not a sizable resource—large enough to support continued high rates of production–lies in fields containing 60 BCF of gas or less. The source of the argument lies in the shape of the field size distribution curve.

[37] American Petroleum Institute, "Quarterly Review of Drilling Sta- tlstlc5,"

**Historically, the cumulative number of gas and** oil fields are distributed according to size in a manner shown in figure 15. In this figure, the size classes 1 through 20 (on the x axis) are scaled so that the upper limit of size class 20 is one-half the upper limit of 19, and so on. As shown in the figure, the cumulative number of fields increases with decreasing size class as a geometric series, down to about size class 13 (or class D in the AAPG notation), and then rapidly levels off. At least a portion of this "truncation," or leveling off, of the field size distribution is undoubtedly due to past economics; many small finds were too small to be economically developed and consequently were reported as dry holes rather than added to the historical record as a class D or E field. Because pipeline gathering systems are required in order to develop gasfields no matter what the field size, and also because the price (per unit of energy) of gas has historically been lower than that of oil, the minimum field size suitable for development is larger—and thus the truncation described above is more severe—for gas than for oil. The crux of the current argument

**Figure 15.—SIze Distribution of Discovered** Oil **and Gas Fields in the Lower 48 States**




SOURCE: R. Nehring, "Problems in Natural Gas Reserve, Drilling, and Discovery Data," contractor report to OTA, 1983.

is, simply, what will the shape of the field size distribution curve look like when the effects of higher gas prices run their course? An important corollary to this argument is, how expensive will it be to discover and develop these small fields, and, consequently, how many of them can appropriately be included in the recoverable gas resource base?

Proponents of the thesis that small fields represent a very sizable resource argue that the trend observed for fields larger than size class D— i.e., a progressive increase in the number of fields discovered in each size class as one moves from the larger field sizes to the smaller–will be continued into the small field sizes below class D once these fields are made the target of intensive exploratory efforts. This argument maintains that the tailing-off of the curve in figure 15 is almost entirely the result of economics and that there are no geologic reasons for the drop in the number of very small fields. Scheunemeyer and Drew,[38] in examining field size distributions in the Gulf of Mexico and the Denver Basin and at three depth intervals in the Permian Basin, show that the "truncation point" of the field size distribution moves to larger field sizes when exploration and development costs are higher, which would be expected if the truncation were economically determined. Also, they note that the point moved to smaller field sizes after gas prices rose and the minimum profitable field size became smaller.

A straightforward argument against the "small fields thesis" is that estimates of large resources from small fields cannot be based on more than an assumption or extrapolation—because no petroleum basin has experienced the intensity of drilling that would be required to find the postulated number of small fields. This argument appears to be a powerful one, but it works equally well against those who might deny the possibility of large numbers of small fields. It probably is not possible at this time to estimate credibly the ultimate number of small gasfields remaining to be discovered in the United States and the resources these fields represent.

A second argument that has been presented is that, in some basins, the field size truncation does not appear to be generated by economics and is more likely to have been caused by geology—the simple lack of sufficient small fields. For example, Nehring[39] identifies subduction and delta provinces, * that account for more than one-quarter of U.S. oil and gas resources, as an example of basins where the number of fields in each size category begins to drop at a size level considerably above any historical field size minimum. Nehring argues that only a portion of U.S. provinces act according to Scheunemeyer and Drew's thesis and that there are four distinct groupings of field size distributions, ranging from one with a rapid increase in the number of fields with decreasing field size (similar to those discussed by Scheunemeyer and Drew), to one with a single peak at about size class D, to one with little increase in the number of fields at field sizes below A or B.

A third argument notes that it takes about 1,000 class E fields to equal three class A fields,[40] and that even a sharp increase in the number of small fields discovered may not be of major significance to the overall resource base. Figure 16 shows the known field size distribution, as in figure 15, and two projected distributions for the ultimately recoverable resource base—one that assumes a doubling' of the approximately 24,000 fields known as of 1975, with most of the increase at the smaller sizes, and a second that assumes a much larger increase at the smaller field sizes, essentially by assuming that the truncation of the number of fields at smaller sizes is **entirely an effect of economics and that the actual number of fields continues to increase logarithmically with**

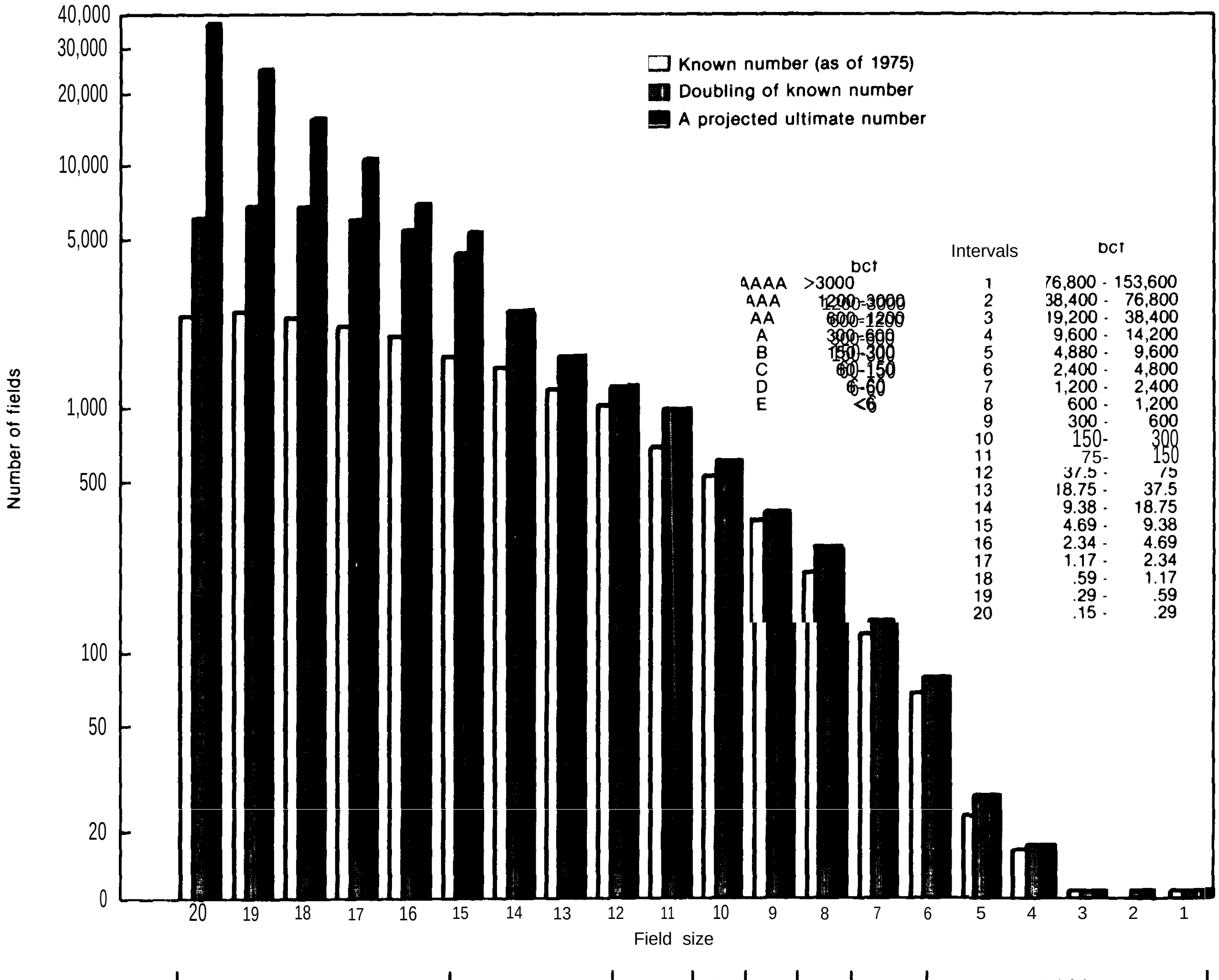
[38] J. H. Scheunemeyer and L. J. Drew, ''A Procedure to Estimate the Parent Population of the Size of Oil and Gas Fields as Revealed by a Study of Economic Truncation, " *Mathematical Geology, vol.* 15, No. 1, 1983.

[39] R. Nehring, *The Discovery of Significant Oil and Gas Fields in the United States, R-2654/I* -USGS/DOE, RAND Corp., January 1981, pp. 78-94. Excursus, "The Distribution of Petroleum Resources by Field Size in the Geologic Provinces of the United States. "

*Subduction provinces are small, linear basins located along the converging margins of plates. They account for about 11 percent of U.S. oil and gas resources in the RAND assessment. The three largest are the San Joaquin, Los Angeles, and Ventura provinces on the west coast. Delta provinces are small-to-medium sized, circular-shaped, and derived from major continental drainage centers. The one producing delta province in the United States is the Mississippi Delta, which accounts for about 17 percent of U.S. oil and gas resources in the RAND assessment.

[40] R. Nehring, *Problems in Natural Gas Reserve, Drilling, and Discovery Data,* op. cit.

**Figure 16.-Known and Projected Size Distributions of Discovered Oil and Gas Fields in the Lower 48 States**




SOURCE: Office of Technology Assessment, based on data from R. Nehring, "Problems in Natural Gas Reserve, Drilling, and Discovery Data," contractor report to OTA, 1983.

decreasing field size. * The first projection produces 48,000 fields, the second about 115,000. Of critical importance is the **difference in resources between the two projections, all of which arises from different assumptions about how the existing truncation of small fields** will "fill in" with future discoveries; it is about 7 **percent of the total resource base represented by the second projec**tion. Extrapolating to the gas resource base (and assuming the "central tendency" range of 902 to 1,542 TCF of ultimately recoverable resources), the assumption that the ultimate number of small gasfields found will be much larger than indicated by the historical field size distribution–might lead to an increase in OTA's estimates of potential gas resources of approximately 60 to 110 TCF.

*The projected distribution is drawn by assuming that the number of fields in each size interval smaller than 100 million BOE (0.6 TCF) is 50 percent greater than the number of fields in the next larger interval.

A fourth argument notes that the small size of the fields makes them only marginally economic at best. For gasfields, especially, many of the fields in the projected distributions may not be economic at current and projected gas prices and therefore may not belong in the recoverable resource base at this time. * In partial support of this argument, USGS studies of the effect of gas price and other economic variables on recoverable gas resources in the Permian Basin indicate considerable sensitivity of the size of the remaining resource to these variables. Table 15 presents estimates of the amount of exploratory drilling that could profitably be pursued and the gas resources that would be discovered by this drilling as a function of wellhead price. **If the model used by the study is correct, the size of the recoverable resource in small fields is sharply sensitive to price (also rate-of-return), although the sensitivity declines at gas prices above $5 or $6 per** MCF,

**New Gas From Old Fields.–Over the lifetime of a field, from initial discovery to depletion, estimates of the field's ultimately recoverable re**sources generally increase with time as normal development probes the full extent of the field and as improved technology and rising prices bring subeconomic portions of the field into the economically recoverable range. * * Although the effects of improved technology and prices have long been acknowledged as critical for increasing oil recovery, gas recovery rates have long been considered to be very high under most conditions and thus somewhat insensitive to price and technology. * Consequently, increases in reserve estimates from known gasfields were generally considered to be primarily an effect of the normal process of exploring for new pools and mapping the boundaries of known pools. This view is now being challenged, as reserve additions are being credited to lowering of the abandonment pressure of depleting reservoirs, to extension of field boundaries into marginal areas (with **low** permeability, thin pay zones, or other conditions adversely affecting economic recovery), to well stimulations and well reworking, and to infill drilling to well spacings lower than the old norm of 640-acre spacing (see box G). For example, from 1969 to 1979, ultimate recovery in the Hugoton-Panhandle field (discovered around 1920) in Kansas, Oklahoma, and Texas Railroad Commission District 10 increased from 71.0 to 84.0 TCF, * * and ultimate recovery in the Blanco Basin fields (discovered from 1927 to 1950) in the San Juan Basin increased from 15.2 to 21.7 TCF.[41] Although growth rates of known fields have varied considerably across different geographic areas, these substantial increases in known recovery from quite old fields are well beyond what might have been predicted by the historic data on growth of old fields.

Claims about the likely **future** growth of older fields have created substantial controversy. There are several areas of disagreement. For **lowered abandonment pressures, analysts disagree about the effectiveness of regulatory measures designed to prevent premature abandonment** of old wells —e. g., incentive prices for low-production-rate wells called "stripper" wells. They also disagree about when the wells would be abandoned if the current low prices did not change. This is important because the lower the "old" abandonment pressure is, the lower is the volume of additional gas that can be recovered in response to a higher price. For **well stimulation and infill drilling, a ma**jor disagreement concerns the extent to which additional gas production from these measures

*in other words, they are subeconomic resources in the McKelvey Box (fig. 8).

* * Reserve estimates in some fields will decrease with time. Small fields are generally considered to be more susceptible than large fields to such reserve "shrink age,"

*However, the *rate* of recovery is extremely *sensitive to these* factors, as is the economic threshold of development for a field

* *This field is not considered a single field by all analysts, nor are its reserve levels corn pletely agreed on. As noted prev iou slv, these are not u nc ommon pro blems, especially with large fields.

[41] Ibid.

**Table 15.—Potential Recoverable Gas Resources From New Discoveries in the Permian Basin (assumed 15 percent of return)**

| Wellhead price $/BOE ($/MMBtu)[a] | Exploration wells drilled (thousands) | New discoveries (TCF) |
|---|---|---|
| 10 (1.50) . . . . . . . . . . | 5 | 4.98 |
| 15 (2.40) . . . . . . . . . . | 12 | 9.17 |
| 20 (3.20) . . . . . . . . . . | 18 | 11.38 |
| 25 (4.00) . . . . . . . . . . | 24 | 13.02 |
| 30 (4.80) . . . . . . . . . . | 29 | 14.12 |
| 35 (5.60) . . . . . . . . . . | 34 | 15.13 |
| 40 (6.40) . . . . . . . . , . . | 38 | 15.81 |

aDollars per barrel of oil equivalent (dollars per million Btu)

SOURCE Geological Survey Circular 828—Future Supply of 011 and Gas From the Permian Basin of West Texas and Southeastern New Mexico, In. teragency 011 and Gas Supply Project, 1980

**Box G.—Sources of "New Gas From Old Fields"**

- **Lowering of abandonment pressure.**—Wells are abandoned when operating and maintenance costs are not balanced by sufficient revenues from gas sales. Because gas-flow rates can generally be associated with wellhead pressures, an "abandonment pressure" can be specified for a given gas price. When gas prices rise, the abandonment pressure is lowered and total recovery efficiency of the reservoir is increased.
- **Infill drilling.**—The original premise of requirements for wide well spacing was that gas reservoirs were sufficiently homogeneous so that very high recovery efficiencies could be obtained with only a few wells, except in fields that had low permeability. More recently, it has been recognized that many reservoirs are heterogeneous in character and are compartmentalized, i.e., composed of relatively small, discontinuous interlaid pockets of gas-bearing rock. Drilling at higher density can intercept pockets that would otherwise not have been drained at traditional wide spacing.
- **Fracturing and acidizing.**—These well stimulation technologies, which have wider application with increased gas prices, are used to speed gas flows and can add to resources by allowing completion of wells in low-permeability sands that otherwise would have been considered as "dry." They do this by allowing a higher recovery during the limited life of the well (at low flow rates, the well may not last long enough to allow full recovery) and by opening up new "pay zones" too small to be economically developed by a new well.
- **Well workovers.**—Marginal wells may also be abandoned because of water encroachment, physical aging of well equipment, and accumulation of sand in the well bore. At higher gas prices, well workovers to correct these problems become possible.
- **Extention of drilling into formerly subeconomic portions of fields.**—In most fields there are areas where, at existing price and technology levels, potentially recoverable gas resources are not exploited because of unfavorable economics. Unfavorable conditions include small reservoirs, low permeability, thin pay zones, and water encroachment. Higher prices and new exploration and production technologies can move these areas from the subeconomic into the economic range.

represents new gas that otherwise would not have been produced, or whether the production instead represents merely an accelerated draining from the field of gas that would eventually have been produced by the existing network of wells, without infilling or stimulation. And for all the measures, there are substantive disagreements about the gas prices necessary to stir major activity, with producers tending to see the need for higher prices and buyers tending to blame poor markets for current disinterest in production enhancement measures.

Another complication in gauging the likely future growth of older fields is the uncertainty surrounding future gas prices in these fields. Aside from the ever-present difficulty of forecasting future market prices for gas, it is not clear to what extent the currently low prices in the old fields will be allowed to rise to the higher market price, or to some other set of defined prices. Although the existing legislation—the NGPA—does define a specific set of price revisions in 1985 and 1987, it is not clear whether or not new legislation will supersede the NGPA's price schedule. Also, it is not possible to accurately project all of the price effects of the NGPA, for several reasons. First, the volume of reserves in each NGPA price category is not accurately known. Second, the eventual price attained by reserves decontrolled by NGPA will depend on unpredictable price negotiations between purchasers and producers. Third, the effects of NGPA provisions that provide higher prices for gas from enhanced recovery are not known because there are inadequate data on eligible reserves and because it is unclear how producers and pipelines will respond to the various bureaucratic provisions in the incentive regulations.

OTA has calculated the potential reserve additions available from four of the five sources of "new gas from old fields" listed in box G; we did not estimate reserves from "extension of drilling into formerly subeconomic portions of fields." We attempted to account for some of the substantial uncertainties by examining two legislative scenarios and by expressing the estimates as a range. The calculations are explained in appendix A at the end of this report. The two legislative scenarios are:

- *Scenario 1:* Continuation of the existing NGPA with its partial price decontrol and price escalation provisions; assume that no new gas pricing legislation will be passed.
- *Scenario* 2: Assume that new pricing legislation is passed that allows any new gas from growth of old fields to attain full market prices without regulatory restraints.

We included only those reserves that are not "new" reserves as defined by the NGPA; roughly speaking, these "old" reserves are associated with reservoirs that began to produce gas before passage of the NGPA. Our conclusions, shown in detail in table 16, are that continuation of the NGPA in its present form (scenario 1 ) could eventually add at least 20 to 35 TCF to cumulative "old gas" reserves if market prices reach $3.50 to $4/MMBtu (1983$), whereas changes in the law that allowed additional reserves to attain the full market price (scenario 2) would yield about 43 to 65 TCF at the same price level.

**Table 16.—Potential Additions to "Old Gas" Reserves From Lowered Abandonment Pressures, Well Reworking, Infill Drilling, and Well Stimulation (TCF)**

| | NGPA | Market prices[a] |
|---|---|---|
| Delayed abandonment and well reworking | 5-13 | 12-31 |
| Infill drilling | 13-20 | 25-28 |
| Well stimulation | 2 | 6 |
| Total | 20-35[b] | 43-65 |

aAssumption. All additional reserves can obtain market Price of $3.50 to $4.00/MMBtu. In infill drilling, drainage from original well *network* to new wells is assumed not to prevent the necessary change in well spacing *rules.*
*bDoes not include reserves added by stripper* incentive, production enhancement incentive,

SOURCE Office of Technology Assessment, "Staff Memorandum on the Effects of Decontrol on Old Gas Recovery, " February 1984.

The above ranges do not reflect absolute minima and maxima because some uncertainties were not accounted for. For example, the range in scenario 1 does not include any contribution to reserve growth from the NGPA price incentives for stripper production and for a variety of production-enhancement measures. We had no basis with which to quantify the effects of such measures, although we do not believe them to be insignificant. Also, the ranges do not include additional reserves that might be added by larger-than-expected growth in reserves from **new** fields discovered since 1978 and field growth resulting from the development of formerly subeconomic areas of fields. Recent annual reserve additions have reflected a high level of "extensions" and "revision s," the two reserve categories that would absorb new reserves from this latter type of development. This might be a signal that there is a substantial potential from this source of field growth.

The numerical results reflect several intermediate conclusions of OTA's analysis. In particular, we discovered that the NGPA allows a substantial amount of old gas to attain higher prices. At least one-third, and probably more, of U.S. "old gas" reserves will attain substantial price increases in 1985 or 1987 under the NGPA, and these increases will trigger significant levels of reserve growth. Also, as a result of extensive *discussions* with geologists and petroleum engineers, we concluded that infill drilling and well stimulation **can** add moderately to gas recovery in most fields. A considerable portion of this infill potential will not occur until available gas prices reach $3.50 to $4/MMBtu, but some fields will be developed at the current infill incentive price of about $2.85/MMBtu. Unfortunately, we were not able to resolve disagreements about the validity of alternate estimates of abandonment pressures, and consequently the ranges of expected reserve growth reflect both extremes.

New **Frontiers, Including Deep Areas.–Even though recent exploratory drilling in the frontier areas has had mixed success and several severe disappointments, considerable areas of untested** or inadequately tested sedimentary rock remain that may hold considerable potential. Even extreme pessimists view areas such as the deepwater Gulf of Mexico, the Anadarko Basin, and the Western Overthrust Belt as having considerable potential. However, it is also inarguably true that areas such as the Gulf of Alaska, eastern Gulf of Mexico, the Southeast Georgia Em bayment, and the Baltimore Canyon have been expensive failures[42] thus far. Unfortunately, it is not easy to document the opinions of the major oil companies—who traditionally are leaders in frontier exploration– because few details of their most recent resource assessments are available to the public. It is clear, however, that some of the majors, notably Exxon and Shell, are pessimistic about the overall Lower 48 potential and the Lower 48 onshore frontier areas. Given the speculative nature of these resources, the range of credible estimates of frontier undiscovered gas must be considered quite wide.

An important part of the controversy over the resource potential of frontier areas involves the economic viability of the potential resources rather than their physical presence. For example, much of the intense deep drilling activity of the early 1980s in basins such as the Anadarko appears to have been a direct response to the very high prices for deep gas (as much as three times the market-clearing price) resulting from the price-controlled market. Prices for deep gas and other categories of gas entitled to special incentive pricing under NGPA have now dropped sharply, and drilling activity has dropped sharply as well. Consequently, some analysts question whether these expensive resources still belong in the economically recoverable resource base. Similar questions have arisen over some of the gas under the deep waters of the continental slope, now included in the USGS assessment and others.

A counterpoint to pessimism about the economic viability of the deep resource is the recent drop in drilling costs in response to the dropoff in activity. Although costs probably will rise when the oversupply in rigs eases, the costs during the drilling boom period probably did not reflect the equilibrium production costs that should be the basis for defining the recoverable resource. Also, deep drillers argue that their growing experience and the rapid advancement of drilling technology will overcome much of the effect of the price drops.

The appropriate placement of these resources inside or outside of the recoverable resource base is complicated by several factors. First, uncertainty about the precise geologic conditions of these resources combined with the recent rapid fluctuations in drilling costs create substantial uncertainty about the cost of producing the resources using today's technology. Second, the present hesitancy of the industry to drill for these resources may not necessarily reflect the resources' lack of long-term economic viability but rather the current lack of gas demand and regulatory uncertainties about decontrol. Third, uncertainty is added by ambiguities in the common definitions of "recoverable resource base," some of which, e.g., allow the possibility of technological improvements that are in line with trends prevailing at the time of the assessment (this is USGS's boundary condition). This greatly complicates the evaluation of resources whose production may involve technological difficulties. Because of these factors, in OTA's opinion the boundary between economic and subeconomic, and consequently the magnitude of the recoverable resource base, is not well defined for the frontier resources.

**Stratigraphic Traps.–Over the cycle of gas exploration, structural traps have tended to be the most favored drilling prospects. As possibilities** for finding new large structures have declined, many explorers have shifted their strategy toward locating subtle stratigraphic traps, i.e., potential reservoirs whose main trapping mechanism is a gradation of the reservoir rock into layers of rock of low permeability laid down by the sedimentation process. Resource optimists expect to find large amounts of resources in these traps.

There are two major arguments against such expectations. First, there have been significant past efforts aimed at finding stratigraphic traps, especially in the Anadarko, Permian, Denver, and Powder River basins.[43] Second, it is argued: 1)

[42] R. Nehring, "The Discovery of . . .," op. cit.

[43] Ibid

that very large stratigraphic gasfields are unlikely to have remained undiscovered in the explored basins of the Lower 48 States because of the fields' large areal extent and the very high density of drilling in these basins; and 2) that most of the stratigraphic traps remaining to be discovered will be small. Nehring[44] also cites geologic arguments against the possibility of finding many large new stratigraphic traps, including the vulnerability of such traps to degradation or dissipation and Nehring's contention that the presence of multiple structural trapping possibilities in basins outside of the stable interior provinces makes it unlikely that many stratigraphic traps will exist outside of these provinces, the source of most past discoveries.

These are strong but not conclusive arguments. New efforts to locate stratigraphic traps can use seismic exploratory techniques not available to the earlier efforts. It is possible, though speculative, that several sizable traps that were "invisible" to earlier techniques could now be located. Similarly, arguments about drilling density are valid but must be tempered by the depth limitations of much of this earlier drilling and the clustering of such drilling around areas considered prospective by earlier standards.

Even if the arguments against finding large stratigraphic traps are correct, there remains significant uncertainty about the number of smaller fields that might exist and the actual potential for finding and exploiting these fields–the same uncertainty that affects assessment of the resource potential of small fields in general. Key factors affecting the potential for producing significant quantities of gas from these fields include gas prices and reductions in the costs of effective exploration techniques.

## Conclusions

Based on the previous discussion, OTA accepts the possibility that discovery trends may have been sufficiently distorted by past regulatory and economic conditions and that sufficient resource possibilities exist in small fields, growth of old fields, and other sources to allow us to accept the estimates of PGC as **possible, but very optimistic—a reasonable upper bound to the probable magnitude of the conventional gas resource base.** On the other hand, we consider the extremely pessimistic estimate of Hubbert to be unlikely, and to a lesser extent we are also skeptical of the RAND estimate. Both come very close to the analogy of "running into a brick wall." Looking ahead to chapter 5, we can see that the Hubbert estimate implies a "conventional gas" production rate of about 3 or 4 TCF in 2000, an astoundingly low value. The RAN D estimate implies that there will be at best only a handful of new exploration plays in the Lower 48, that these will be only moderate in size (2 to 10 TCF), and that there will be no really large "surprises" left; we believe this is possible, although quite pessimistic. However, the RAND assessment appears to have underestimated the potential for reserve growth in known fields, and it apparently has excluded some gas in low-permeability reservoirs that is currently economically recoverable. Therefore, we consider a credible lower bound to be somewhat higher than the RAND estimate.

In conclusion, our best guess–and we chose this word carefully—is that a reasonable range for the magnitude of remaining conventional natural gas resources, **recoverable under technological and economic conditions not far removed from today's, * is about 430 to 900 TCF as of the end of 1982. This is not really a very wide range, given the basic uncertainty associated with resource assessment, but** it **is** a wide range with respect to future production potential. The two ends of the range have very different implications about how difficult it is going to be to continue to replenish our current inventory of gas reserves over the next decade or two, and they have profound implications about what the role of natural gas in our energy economy will be in 2000. OTA believes that if the lower end is correct, reserve additions will fall off drastically within a few years, with production rates dropping in response. On the other hand, the upper range implies the potential for a very positive future for conventional gas production during this century. The next chapter explores these production issues in greater detail.

[44] Ibid.

*Including gas in low-permeability reservoirs that otherwise satisfies the conditions. This recognizes the ambiguous boundary between "conventional" and "unconventional" gas in such reservoirs.

## Chapter 5

# Gas Production Potential

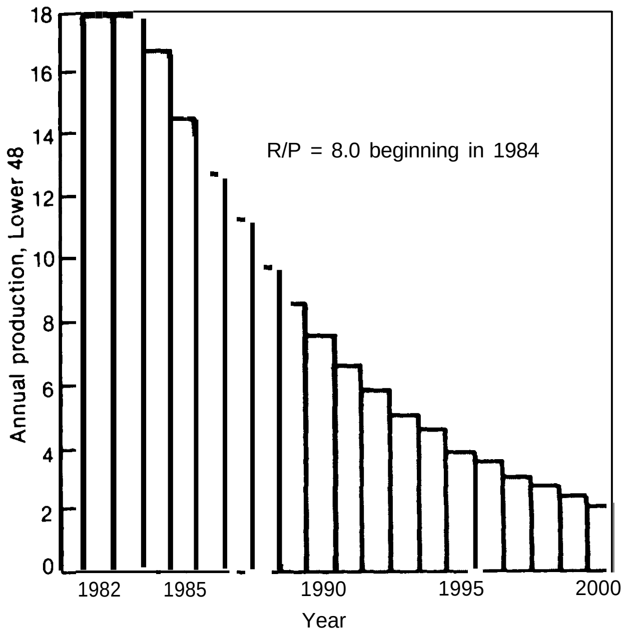
## Contents

# Chapter 5
# Gas Production Potential

There are a variety of alternative approaches to estimating the future gas production potential of the United States, including the use of complex computer programs using econometric, process engineering, or system dynamics approaches to model separately the gas exploration, development, and production processes. Although during the course of this study OTA examined several complex models in detail, we have chosen to use four relatively simple techniques to project future production potential. This approach reflects the high costs of using the complex models and some doubts we entertain about the expected accuracy of these models as forecasting tools. These doubts do not necessarily extend to the usefulness of the models as policy analysis tools; often, these models offer the valuable ability to test alternative policies under carefully controlled conditions.

Of the four approaches used by OTA to project the mid- to long-term (1 990 and beyond) production potential for natural gas in the Lower 48 States, three focus specifically on the potential for continued additions to U.S. proved reserves. **The addition of new reserves to the U.S. gas system is the primary determinant of future gas availability.** The importance of new reserves can be illustrated quite simply by drawing the production that would likely result from the **failure to add to reserve levels and reliance instead on current proved** reserves as the **sole** "inventory" for production to draw on (see fig. 17). Assuming a constant reserves-to-production (R/P) ratio of 8,0, beginning in 1984, production would immediately begin to drop with shocking rapidity to about 2 trillion cubic feet (TCF) by the end of the century. *

**Figure 17.–Natural Gas Production From 1981 Lower 48 Proved Reserves**




SOURCE: Office of Technology Assessment

Of the three approaches focusing on continued additions to U.S. proved reserves, the first projects future reserves by examining historical trends in all components of reserve additions (new field discoveries, extensions, new pool discoveries, and revisions), examining the underlying causes of the trends, and extrapolating into the future based on OTA's expectations of future conditions. In this extrapolation, we have drawn heavily on the insights gained in our examination of gas resource base assessments. The second approach projects only new field discoveries and then applies a "growth factor' to these discoveries based on historical experience with the growth of new fields and OTA's judgment about how the growth rate may have changed. The third approach is based on a geologist's * region-by-region examination of available gas resources and past exploratory success. In all three cases, production rates are calculated from reserve data by projecting future levels of the R/P ratio.

The fourth approach borrows a method used by M. King Hubbert in 1956,[1] tying future pro-

*Conceivably, the initial reduction in production could be slowed by drilling additional development wells, effectively lowering the R/P ratio, The end result of this strategy would be, however, an even more rapid product ion collapse occurring a few years later than that shown in fig. 17.

*Joseph P. Riva, Jr., of the Congressional Research Service.

[1] Described in M, K. Hubbert,' 'Tee h niques of Production as Applied to the Product Ion of Oil and Gas, " *Oil and Gas Supply Modeling*, S. I. Gass (cd.), National Bureau of Standards Special Publication 631, May 1982.

duction directly to available resources by drawing freeform plots of the complete natural gas production cycle in such a manner that the cumulative production conforms to existing resource base estimates—in this case, to the estimates of Hubbert, the U.S. Geological Survey (USGS), and the Potential Gas Committee (PGC).

In each of the four approaches, ranges of production potential are estimated based on alternative assumptions about the magnitude of the resource base, efficiency of the exploratory process, and other factors.

OTA's use of four approaches, and alternative assumptions within the approaches, reflects our skepticism of our own and others' ability to project future gas production rates with any precision. A "most likely" or "best" projection was deliberately avoided because we believe that such a projection, beyond 5 years or so into the future, would be futile. Our purpose in this section is to illustrate the **plausible range** of possible future production rates and the general effects on production estimates of different interpretations of the causes of past trends and different assumptions about future conditions. The first approach is our slight favorite, but only because its level of disaggregation forces the analyst to deal more explicitly with the underlying causes of past events. This approach is discussed in the greatest detail.

At the end of the chapter, a variety of gas production forecasts by public agencies, private companies, and institutions are presented and discussed.

## APPROACH NUMBER 1–PROJECTING TRENDS IN THE INDIVIDUAL COMPONENTS OF RESERVE ADDITIONS

The first approach separately projects trends in reserve additions from new field discoveries, new pool discoveries and extensions, and revisions.

### New Field Discoveries

**The discovery of new gasfields represents the single most important force necessary for building a sustainable natural gas supply** because a new gasfield not only adds to **current** reserves but also provides a source of considerably larger additions to future reserves through field growth after the discovery year. Reserve additions attributable to extensions and new pool discoveries and, to an extent, to revisions, are all, in fact, the inevitable consequence of previous new field discoveries. Therefore, if new field discovery rates increase or decrease, then at some point in the near future, reserve additions from extensions and new pool discoveries will almost certainly increase or decrease in a like manner.

### Factors Affecting New Field Discoveries

**The rate** of annual additions to reserves from new field discoveries depends on a variety of factors, but most importantly on:

- **The undiscovered resource base.**–The physical nature of the resource base—including the amount of resources remaining to be found, the distribution of field sizes, the locations of fields, the distribution of types of geological traps (more or less difficult to pinpoint with available exploration techniques), and other physical attributes—is considered by some to be the single most important determinant of future new field discoveries.
- **Exploration technology .-The rapid advance** of exploration technology, for example, computer-aided seismic technology, affects drilling success rates and, consequently, overall discovery rates, Also, technological improvements have opened up to commer-

cial exploitation some areas whose complex geology had previously prevented acceptable success rates. Consequently, these improvements have expanded the recoverable resource base. Development of the Western Overthrust Belt is an important example of this effect.

- **Drilling and production technology .-Improvements in production technology create an expanding recoverable resource base and, in turn, an increase** in targets for the drill. For example, massive hydraulic fracturing technologies allow exploitation of fields in sands of low permeability that previously would have been subeconomic. improvements in offshore drilling technology allow exploitation of gasfields in deeper and more hostile waters.
- **Current and perceived future gas prices and other economic variables. -Such variables affect the propensity to drill and determine** where to draw the line between a producible well and a dry hole. In some cases, the higher prices allow the use of well stimulation techniques that would otherwise be too expensive, allowing successful production to be achieved from a well that would otherwise have had too low a flow rate. Additionally, the minimum acceptable reservoir size for production has grown smaller. The **relative** prices of gas and oil are important also because these will determine whether drilling will be preferentially aimed at targets where gas or oil are more likely to be found.
- **Schedules, financial terms, and other aspects of leasing.**–These also determine the number of attractive targets available for exploratory activity.
- **industry willingness to take risks.-All of the above factors and others play a role in determining the propensity of the exploration segment of the industry to assume the risks of wildcat drilling in unproved areas where much of the gas resource potential is thought to exist. Because this type of drilling often involves hostile environments and large capital requirements, much of this drilling is the domain of the major integrated oil companies and the large independents. Consequently, those factors that strongly affect the** cash flow, capital availability, and economic incentives for this group of companies are particularly likely to affect the industry's propensity for risk-taking.
- **Historic prices and exploratory experience.** –There always exists an inventory of new field prospects known to explorers through past exploratory activities but undrilled or (in the case of "dry holes") uncompleted because of economic conditions or the availability of more promising prospects elsewhere. The key determinants of the size and character of this inventory are past exploratory experience and price profiles. The nature of the inventory is, in turn, an important determinant of new field discovery rates in the short term, especially during the period following a change in price levels or regulatory controls.

## Historical Variation of New Field Discoveries

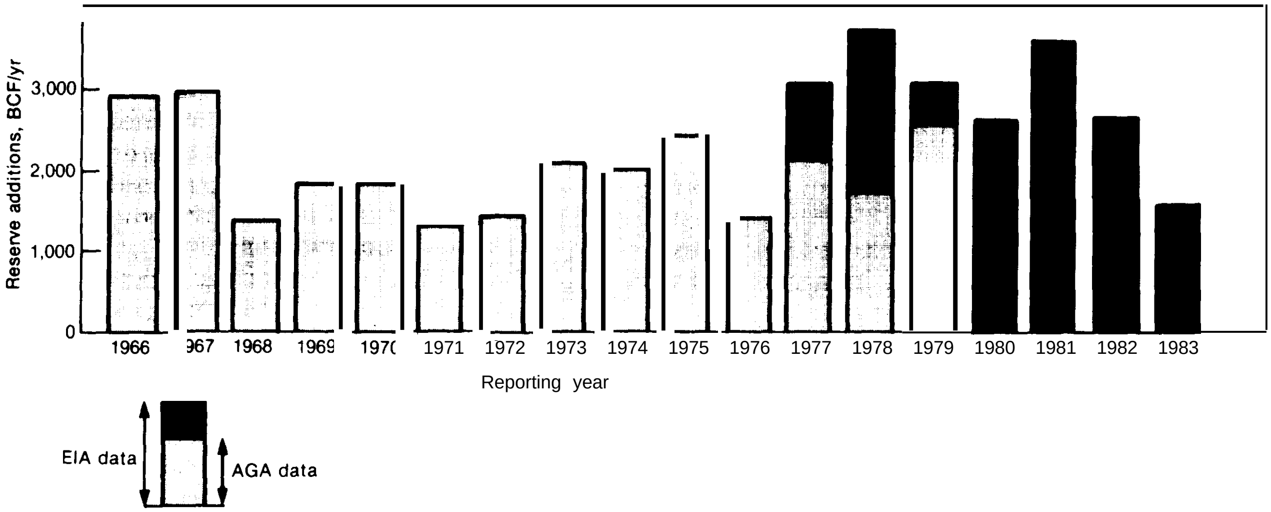
During the 14 years of American Gas Association (AGA) data availability, * the annual additions of new field discoveries in the Lower 48 States remained fairly steady, if somewhat cyclic, varying between a high of 2.9 TCF and a low of 1.3 TCF. (See fig. 18, which also shows the Energy Information Administration (EIA) data for 1977 to 1983.) From 1967, the last year in which AGA estimated that total reserve additions exceeded production, until 1979, the average of new field discoveries was 2.0 TCF. Similarly, nonassociated new field discoveries were equally steady, with a 14-year average of 1.7 TCF. Consequently, new field discoveries played a surprisingly small direct role in annual reserve additions during this period; * * they averaged less than 20 percent of all annual additions from new discoveries and extensions and never exceeded 25 percent in any year.

Although the reserve additions reported as new field discoveries remained steady during this period, the size distribution of the fields discovered did not. As shown earlier in table 12, the

*Actually, AGA compiled reserve additions data since 1947, but only began separately estimating new field discoveries in 1967.

**Clearly they did not play a small indirect role since many of the new pool discoveries and extensions in this period represented development of the fields discovered earlier in the period.

**Figure 18.–Additions to Lower 48 Naturai Gas Proved Reserves: New Field Wildcat Discoveries, 1966.83 (BCF)**




SOURCES: Office of Technology Assessment, baaed on data from Energy Information Administration, U.S. Crude *Oil,* Natural Gas, and Nafural Gas *Liquids Reserves— 1983 Annual Report, DOE/EIA.0216 (83),* October 1964, and American Petroleum Institute, American Gas Association, and Canadian Petroleum Association, Re-Serves of Crude 0il, Natural Gas Liquids, and Natural Gas *in the* United States *and Canada* as of *December 37, 1979,* vol. 34, June 1980.

average size of new gasfields became considerably smaller (reported year-of-discovery reserves of 1.85 billion cubic feet [BCF] per successful new field wildcat in 1979 v. 18.56 BCF per successful new field wildcat in 1966). Furthermore, the lower average did not imply only a reduction in discoveries of giant fields; although this did occur, another change involved a very large increase in the number of very small class E fields* brought into production.

Because of the smaller size of newly discovered fields, a steady expansion of successful exploratory wells was required just to maintain the rather low annual discovery rate of the period. For example, completions of new field (gas) wildcats in the onshore Lower 48 increased from 126 in 1968 to 671 in 1979. Because of the substantial improvements in success rates (see fig. 14) for all new field wildcat drilling (from 8.5 percent in 1968 to 19.0 percent in 1980), however, actual drilling rates did not have to increase in proportion to the rate of completion. From a low of 4,463 wildcat wells in 1971, drilling reached 6,413 wells in 1979 and 8,052 in 1981.

The more recent (1977 to 1983) EIA new field discovery data (fig. 18) show considerable year-to-year variation with no apparent trend aside from the recent drop associated with the current poor market, and are made even more difficult to interpret because of the break with the AGA data series. However, the EIA estimates of new field discoveries were higher during 4 of the first 5 years of record than **any** AGA-recorded discovery rate from 1966 to 1979. Of interest is the source of these discoveries. Although areas like the Western Overthrust Belt and deep Anadarko Basin have been in the forefront of media coverage, most new field discoveries continued to come from more traditional gas-producing areas —onshore and offshore (Gulf of Mexico) Louisiana and Texas. For example, during both 1980 and 1981 these two States provided two-thirds of the total magnitude of reserve additions from new field discoveries in the Lower 48.[2]

*Class E fields contain less than 6 billion cubic feet of recoverable gas.

[2] EIA, (J. s. *Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, 1980 and 1981 Annual Reports,* DOE/EIA-0216 *(80)* and (81), October 1981 and August 1982.

## Implications

The following key issues pertaining to new field discoveries remain essentially unresolved:

- Can the 1968-79 trend in new field discoveries—essentially a steady cycling around an average of 2 TCF/yr or so—be continued well into the future? If optimists about the gas resource potential of small fields are correct, a continuing strong exploratory drilling effort should be able to maintain this level for a number of years. If the pessimists about small fields—and about the remaining resource base in general—are correct, reserve additions from new field discoveries might drop within a few years.
- Do the higher EIA estimates of 1977-82 new field discoveries represent an actual increase, or are they the result of the change in reporting methodology? Does the EIA methodology place more of a newly discovered field's **ultimate** reserves into the first year reserve estimate, leaving less room for secondary (extension and new pool wildcat) discoveries? If the EIA values represent a true increase in new field discovery rates, the sustainability of a high rate (perhaps 3.5 TCF/yr) of new field discoveries would seem to depend either on the availability of new giant fields or on extremely high rates of exploratory drilling and the availability of massive numbers of small fields, supported by either or both strong price incentives and continued improvements in exploration technologies (especially in terms of lowering the cost of detailed geological surveys).

The comparison of the three overlapping years of EIA and AGA data in figure 18 is tantalizing because the difference between the two data sets is considerably smaller in 1979 than in 1977 and 1978, and the EIA methodology changed in 1979. Some analysts have chosen to use AGA data until either 1978 or 1979, and EIA data thereafter, assureing that the two series are essentially continuous. However, the coincidence between the 1979 EIA and AGA estimates for new field discoveries may be an accident; the two data sets differ considerably for all of the other reserve addition categories in 1979.

The failure to resolve the above issues implies that a credible range for future new field discovery rates would be quite wide. Although defining the range is a matter for subjective judgment, OTA would put the range at about 1.5 to 3.5 TCF/yr for the next 10 to 15 years, **assuming that exploratory drilling remains active for the period. * The range** for the next 2 or 3 years should be narrower, however, perhaps 2.0 to 3.5 or 2.5 to 3.5 TCF/yr. The reasoning for these judgments is as follows:

- The high end of the range for the immediate future is based on the distribution of new field sizes. Because the recent high discovery rate did not depend on discovering giant fields—notoriously erratic occurrences –but on employing a very large number of exploration teams to discover many medium-sized and small fields, the physical ability of the system to maintain its recent new field discovery rates should logically be quite high unless the gas "bubble' '-and the current slump in drilling and all other exploratory activity —conti nues.
- To obtain the lower end of the 10-to 15-year range, we assumed that the 1970s AGA data more accurately reflect the likely future and that continuing resource depletion will lead to poorer prospects and a slump from the average 'of 2.0 TCF/yr during that period. Also, it was assumed that the major reasons for the higher EIA values are methodological and do not reflect an **actual** increase over discovery rates reported by AGA. Consequently, the 1.5 TCF/yr reflects AGA conventions and probable followup field growth. The discovery levels actually **recorded by EIA would be expected to be higher than this value, but the reserve growth caused by extensions and new pool tests would then be lower than would be predicted by pre-EIA historical experience.**
- The higher end of the 10- to 15-year range assumes that the EIA data accurately reflect a major upward shift in the finding rate (volume

*Drilling is now in a substantial slump. The ranges of reserve additions discussed here would be unrealistically high if the current "bubble" in gas deliverability and the related difficulties in marketing new gas were to continue.

of gas discovered per unit of exploratory activity). Additionally, it is assumed that continued improvements in exploration and production technologies allow further increases in finding rates and/or that exploratory drilling rates are increased. This end of the range is aligned with a large resource base.

## Extensions and New Pool Discoveries

As already noted, a new field is generally not sufficiently defined in its year of discovery to allow the "new field discoveries" portion of reported reserve additions to represent all or most of the actual recoverable resource in that field. In the years following discovery, additional exploratory wells are drilled to delineate the full extent of the resources present in the field. Wells that probe the boundaries of reservoirs or fields in order to establish their productive area are called extension wells or extension tests. Wells that search for additional reservoirs within already discovered fields are called new pool tests or new pool wildcats. The reserve additions from extension wells and new pool wildcats represent the results of a secondary or followup discovery process for new fields.

### Factors That Affect Extensions and New Pool Discoveries

As with new field discoveries, the major determinants of extensions and new pool discoveries are the magnitude and nature of the "target" (in this case, not the undiscovered recoverable resource base, but only that portion of the remaining resource associated with discovered fields), the technology available to find the gas, and the nature of the incentives to drill:

- **The target.**—The "resource base" for extensions and new pool discoveries is the inventory of discovered but incompletely delineated fields. Limited data from the late 1960s and 1970s indicate that the major part of new field growth has occurred within the first 5 years after discovery. Consequently, unless incentives for gasfield development are lacking, * the magnitude of extensions and new pool discoveries should be strongly **and positively** tied to recent new field discoveries. Additionally, measures that increase current new field discoveries should soon lead to increases in extensions and new pool discoveries as the new fields are further developed.

  Aside from the total gas volume represented by the "target," that is, the inventory of discovered fields, the geological characteristics of the fields will also play an important role in determining future extensions and new pool discoveries. For example, older fields that were incompletely developed because a substantial portion of their in-ground resource was subeconomic* at the time of discovery are now good targets for new exploratory efforts. The size and complexity of newly discovered fields will partially determine the relationship between the initial year-of-discovery reported reserves and the later extensions and new pool discoveries that signify further development of the fields. Because the discovery wells of smaller, less complex fields can generally "prove" a high percentage of their total resource, these fields may offer less opportunity for this later development than was the case with the generally large, complex fields of earlier decades.
- Technology.-The same technological factors that affect new field discoveries affect extensions and new pool discoveries. Computer-assisted seismic technology is considered especially important in allowing extension wells and new pool tests to be drilled with high success rates. Fracturing technologies, by opening up previously uneconomic reservoir margins and tight reservoirs in already discovered fields, expand the target resource available.

  Advancements in exploratory technology have other, varied effects, however. For example, advanced seismic techniques, by offering a highly accurate picture of the potential of new fields shortly after discovery, may encourage a larger proportion of the ultimate recoverable gas to be drilled and "proved"

*The current gas "bubble" provides a disincentive for field development.

"Because of the small size or low permeability of the reservoirs or the low quality of the gas.

in the initial year-of-discovery, leaving less room for followup discoveries. Advanced seismic techniques also may help compress the remaining field delineation into a shorter span of time, leading to increases over expected levels in extensions and new pool discoveries* for a few years after discovery of the field, followed by a later decrease in expected levels of these reserve additions.

## Historical Variation of Extensions and New Pool Discoveries

Figure 19 and table 17 illustrate the variation of extensions and new pool discoveries** in the Lower 48 States from 1966 to 1983. Extensions have consistently played the major role in total reserve additions. After declining in the mid to late 1960s, they remained stable around 6,000 BCF/yr from 1969 to 1976 and began to move upwards thereafter. As with the other categories of reserve additions, the shift to EIA data complicates an interpretation of the past few years. According to that data, however, extensions **by themselves** produced reserve additions of 10 TCF in 1981, equaling or surpassing **total** reserve additions in most years of the **1970s.**

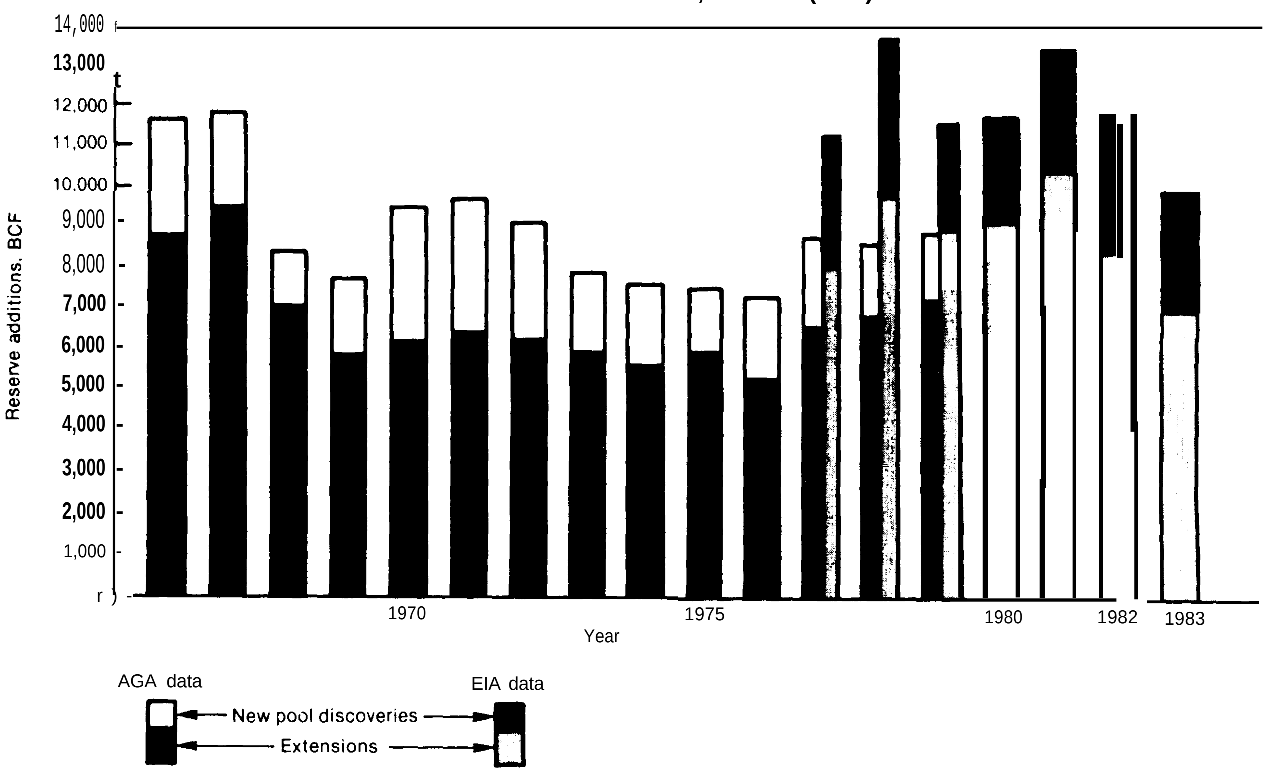
Some of the underlying causes of these trends may be understood by examining the trends in extensions of individual PGC reporting areas.[3] Extensions tend to be concentrated in only a few of these areas. Before 1968, field growth (primarily in relatively deep fields) in the Permian Basin

*That is, increases over the discovery rates projected by using historical data.

**As noted previously, new pool discoveries are reported as "new reservoir discoveries in old fields" in the AGA and EIA reserve reports.

[3]From R. Nehring, "Problems in Natural Gas Reserve, Drilling, and Discovery Data," contractor report to OTA, 1983.

**Figure 19.-Additions to Lower 48 Natural Gas Proved Reserves: Extensions and New Pool Discoveries, 1966-83 (BCF)**




SOURCE: Office of Technology Assessment, based on AGA and EIA data,

**Table 17.—Additions to Lower 48 Natural Gas Proved Reserves: Extensions and New Pool Discoveries 1966-83 (BCF)**

| Year | Extensions | New pool discoveries | Total |
|---|---|---|---|
| 1966 | 8,767 | 3,110 | **11,877** |
| 1967 | 9,472 | 2,420 | **11,892** |
| 1968 | 7,037 | 1,426 | **8,463** |
| 1969 | 5,800 | 2,043 | **7,843** |
| 1970 | 6,146 | 3,363 | **9,509** |
| 1971 | 6,375 | 3,361 | **9,736** |
| 1972 | 6,154 | 3,096 | **9,250** |
| 1973 | 5,931 | 1,970 | **7,901** |
| 1974 | 5,693 | 1,952 | **7,645** |
| 1975 | 5,926 | 1,649 | **7,575** |
| 1976 | 5,337 | 1,994 | **7,331** |
| 1977 | 6,569 (8,056)[a] | 2,144 (3,301) | **8,713 (1 1,357)** |
| 1978 | 6,720 (9,582) | 1,964 (4,277) | **8,684 (13,859)** |
| 1979 | 7,112 (8,949) | 1,690 (2,566) | **8,802 (1 1,515)** |
| 1980 | (9,046) | (2,577) | **(11,623)** |
| 1981 | (10,485) | (2,994) | **(13,429)** |
| 1982 | (8,349) | (3,419) | **(11,768)** |
| 1983 | (6,908) | (2,965) | (9,873) |

aThe values in parentheses are from EIA data; all other values are AGA reserve data.

SOURCES: Office of Technology Assessment, based on data from Energy Infer. mation Administration, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves— 1983 Annual Report, DOE/EIA-0216 (83),* October 1984, and American Petroleum Institute, American Gas Association, and Canadian Petroleum Association, Reserves of *Crude Oil, Natural Gas Liquids, and Natural Gas in the United States and Canada as of* December 31, 1979, vol. 34, June 1980.

provided a major fraction of total U.S. extensions—e. g., 43 percent in 1966. A sharp decline in Permian Basin reserve growth in 1968 was the primary reason for the general decline in extensions at the same time. The increase in extensions nationwide, beginning in 1977, resulted primarily from increases in:

- Western Overthrust Belt development;
- development of the deep Anadarko Basin;
- tight gas sand development in Northeast Texas, Arkansas, and Louisiana; and
- Texas gulf coast development, including offshore fields, the South Texas Lobo Trend, and tight sands in the Austin Chalk.

## Implications

Although the shift in data collection from AGA to EIA complicates interpretation, the sum of extensions and new pool discoveries has apparently been increasing from about 1976 to the present, In the AGA data, however, the increase only takes these "followup" discoveries back toward the levels achieved during the brief surge in new pool discoveries that occurred in the early 1970s. **The EIA data show a considerably higher level** of "followup" discoveries at about the levels that AGA estimated for 1966 and 1967.

In order to understand the recent variations in extensions and new pool discoveries, it is generally necessary to track the new field discoveries that serve as the "inventory" for the secondary exploration process. There is no obvious trend in the **national** new field discovery pattern (fig. 18) that would explain the recent higher level of secondary discoveries; AGA new field discovery data in the period immediately before this apparent surge in secondary discoveries show no similar increase. Consequently, in order to understand fully the causes of the recent surge, it probably is necessary to undertake a detailed examination of data at the level of individual fields. This is beyond the scope of OTA's study. However, some reasonable hypotheses can be fashioned based on the available data.

One possible explanation for the recent increases in extensions and new pool discoveries is that the increment over "normal" levels represents the delayed development of fields discovered earlier but not developed for economic reasons. The **dip** in new pool discoveries from about 1973-76 (fig. 19), which occurred despite an earlier period of steady new field discoveries that normally should have maintained steady levels of extensions and new pool discoveries, supports this explanation.

Some field-specific data also support a "delayed development" cause for part of the increases. For example, recent extensions in the Austin Chalk fields in southeast Texas appear to be tied to old fields that were marginally economic when discovered and had never undergone major development before recent price increases encouraged a reexamination. Because these fields were not "new," recent discoveries were probably recorded as extensions and new pool discoveries, even though there was little in the way of previously recorded new field discovery "inventory" to trace as the statistical cause of these secondary discoveries.

Similarly, another of the areas providing a substantial fraction of the increased extensions—the Western over-thrust Belt–probably also followed a delayed pattern of development. In this area, there was little incentive to delineate immediately the first new fields discovered because there was no means to transport the gas. Consequently, a substantial inventory of new fields could have built up until a point was reached where it became clear that the area contained sufficient reserves to justify a pipeline. Attaining this level of reserves would have introduced an incentive for field delineation, and secondary exploration would have then proceeded to cause a surge in extensions.

An additional cause of the recent higher recorded levels of secondary discoveries could be an acceleration in the pace of field size delineation and development, Such an acceleration would result in the field size growth that in the past might have been spread out over a 60-year span being compressed into a shorter time period, with higher levels of annual reserve additions during this shorter period. Accelerated field size growth would be an expected consequence of higher gas prices, although the recent problems of reduced gas demand would tend to have the reverse effect, that of slowing down the pace of growth.

To summarize, two possible causes for recent increases in extensions and new pool discoveries are an accelerated field development pace and the delayed development of earlier new field discoveries whose development was (at least in part) initially uneconomic. If these are indeed the primary causes of the increases, this has important implications for future reserve additions. First, the faster pace of development means that **fewer** opportunities for field growth will be available in the later years of development; this should tend to decrease future reserve additions unless the rate of new field discoveries increases. Second, unless additional opportunities for growth from older fields are available, this source of "inventory" for extensions and new pool discoveries is unlikely to allow continuation of the currently high reported levels of reserve additions. Although continuing technological advances and future gas price increases could offer some potential for sustaining reserve additions from older fields, the actual potential for reserve additions from this source is controversial. * In any case, most of any additional reserve growth from older fields seems likely to be attributed to infill drilling and other causes that will be reported as positive revisions rather than as extensions and new pool discoveries.

Recent and future discoveries of new fields still provide the primary source of inventory for future extensions and new pool discoveries. Consequently, future reserve additions from extensions and new pools depend heavily on the meaning of the sharply higher levels of new **field discoveries reported during 5 of the past 7 years by** EIA. As discussed in the "New Fields" section, OTA suspects that part of the reason why EIA's compilation of new field discoveries is substantially greater in magnitude than the levels shown by AGA is that the EIA data captures some of the reserves that AGA would have reported as second-year extensions, new pool discoveries, or positive revisions. If this is correct, the "growth factor" that should be applied to EIA's new field discovery data to account for field growth after the year of discovery will be smaller than the growth factor applicable to **AGA** data. For this reason, we do **not** believe that continuation of high levels of extensions and new pool discoveries is probable under current conditions.

Aside from the effects of the change in reporting, there are other reasons to believe that future levels of extensions and new pool discoveries may drop. First, much of the field growth in the past has come from the giant fields that took years to develop. A large percentage of recent new field discoveries, however, are small, class E (less than 6 BCF of recoverable gas) fields that will require little additional exploratory drilling past the initial wildcat. Second, the suspected acceleration in the pace of field development implies that some of the development that might in the past have taken place in the second year (and that would have been reported as extensions and new pool discoveries) now takes place in the first and will be reported as part of the "new field discoveries" reserve additions. Finally, the high capital requirements for developing new fields in hos-

*As discussed in ch. 4, "New Gas From Old Fields."

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tile environments–an increasing part of the remaining resource—demand a more thorough initial estimate of reserves, possibly leading to lower (statistical) growth later on.

To conclude, OTA does not believe it is likely that recent reserve additions from extensions and new pool discoveries of 12 to 14 TCF/yr will be sustained in the future even if the gas "bubble" ends and its negative effects on drilling cease, instead, we project a range of 6 to 11 TCF/yr as an average over the next 10 to 15 years, except that for 1985-86 we project a range of 8 to 12 TCF/yr. The sole possibility of a higher long-term rate of reserve additions from this source lies with the discovery of several new, complex, super giant gasfields with large growth potentials; however, this possibility appears low.

## Revisions

Revisions indicate changes in the volume of proved reserves that result from new information gained by drilling and production experience and corrections made to earlier estimates during the reporting year.

The AGA and DOE/EIA reporting of revisions is not identical because EIA has a separate category of "adjustments and corrections" that includes adjustments for changes in data samples, corrections of reporting errors, inclusion of late responses, and other factors. Theoretically, AGA's revisions should be equivalent to the sum of EIA's revisions, adjustments, and corrections. However, the data gathering and analysis methods used by the two surveys are radically different, and their reserve and reserve addition estimates in the 3 years of overlap do not show good agreement, Consequently, they are not equivalent, although in displaying historical trends AGA revisions will be compared to EIA revisions plus adjustments and corrections.

### Factors Affecting Revisions

Generally, revisions occur because of uncertainty associated with estimating the extent of the underground reservoir rock within a trap, the porosity and permeability of that rock, water saturation, pressure, and other physical reservoir characteristics that affect the cumulative volume of production over the life of the reservoir. Revisions tend to be a "catchall" category of reserve additions and deletions, and the many sources of revisions are difficult to separate out of the data. These sources include:

1. new knowledge gained by normal development drilling and production experience (e.g., changes in reservoir pressure decline trends that indicate that earlier estimates were incorrect);
2. numerical errors in the original compilation of reserve estimates;
3. discoveries for which reporting had been delayed;
4. development drilling on a closer spacing that "discovers" new reserves;*
5. changes in production economics that lower or raise the abandonment pressure of a reservoir or that allow or prevent the use of well-stimulation techniques that increase recovery efficiency;
6. knowledge gained from extension tests that indicate a decrease in the estimated proved area of a reservoir or field (an **increase** would be recorded as an extension); and
7. miscellaneous statistical corrections and adjustments to the data.

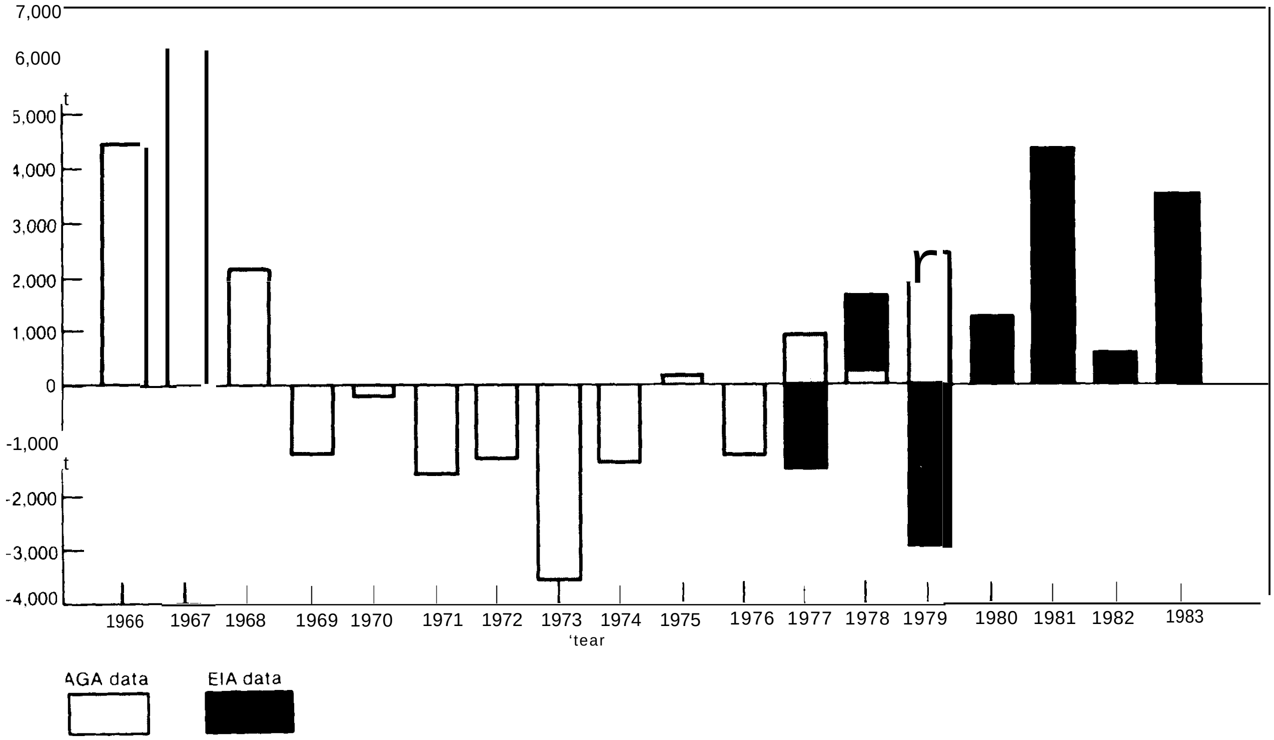
Sources 2, 3, and 7 are considered "Adjustments and Corrections" by EIA and are reported separately.

### Historical Variation of Revisions

From 1966 to 1983, net revisions were easily the most volatile of any of the four types of reserve additions. In the data reported by AGA for the contiguous 48 States, revisions varied from +6,256 BCF in 1967 to –3,546 BCF in 1973. In the EIA data for the same area, revisions plus adjustments and corrections varied from –2,91 1 BCF in 1977 to +4,346 BCF in 1981. Consequently, the year-to-year changes in revisions were the primary determinant of the year-to-year changes in gross reserve additions during the past 16 years. **As** shown in figure 20, **a** series of sub-

*New reserves "discovered" by a development well would be recorded as a revision if the gas is located in a pocket within the established boundaries of a reservoir yet is physically isolated from the reservoir's main drainage system and would not otherwise be produced.

**Figure 20.–Additions to Lower 48 Natural Gas Proved Reserves: Revisions As Reported,[a] 1966-83 (BCF)**




aNOTE: EIA plots for revisions + adjustments and Corrections.

SOURCES Office of Technology Assessment, based on data from Energy Information Administration, *U S Crude 011, Natural Gas, and Natural Gas Liquids Reserves— 1983 Annual Report, DOE/EIA-0216 (83),* October 1984, and American Petroleum Institute, American Gas Association, and Canadian Petroleum Association, *Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States and Canada as of December 31, 1979, vol* 34, June 1980

stantial positive revisions in the mid-1960s changed to net negative revisions in almost every year in the 1970s, particularly in the onshore contiguous 48 States. As discussed later, understanding the role of these revisions is important in interpreting reserve changes during this period.

The largest negative revisions in the 1970s were reported in onshore south Louisiana and Texas Railroad Commission Districts 1, 2, 3, 4, and 6. Together, they contributed a total of over 30 TCF and proved to be remarkably persistent, continuing throughout the 1970s in both the AGA and EIA data. They were concentrated in older fields that had been producing for one to three decades before the revisions began.

The negative revisions in these six areas appear to be causally related to a situation that encouraged optimism in reserve calculations. During the **1930s, 1940s,** and 1950s, **exploration** for natural gas in and adjacent to the gulf coast was highly successful. As a result, much more gas was discovered than could be produced, given the small size of the national natural gas market at the time. The transmission companies, having contracted for reserves with a productive capacity substantially exceeding what they could market, developed a system for prorating production among operators on a basis of remaining reserves (i e., the larger an operator's reserves, the more gas the transmission companies would buy). This created a strong incentive for the operators to provide the most optimistic estimates of reserves they could justify. By 1970, following years of increasing production and gradual depletion, the operators were beginning to realize that *reserves* were overstated. The size, timing, and geographic distribution of the reported negative revisions that followed depended primarily on when each major operating company recognized the problem and how they decided to revise their estimates downward, choosing to take them all at once or spreading them out over several years.[4]

## Implications

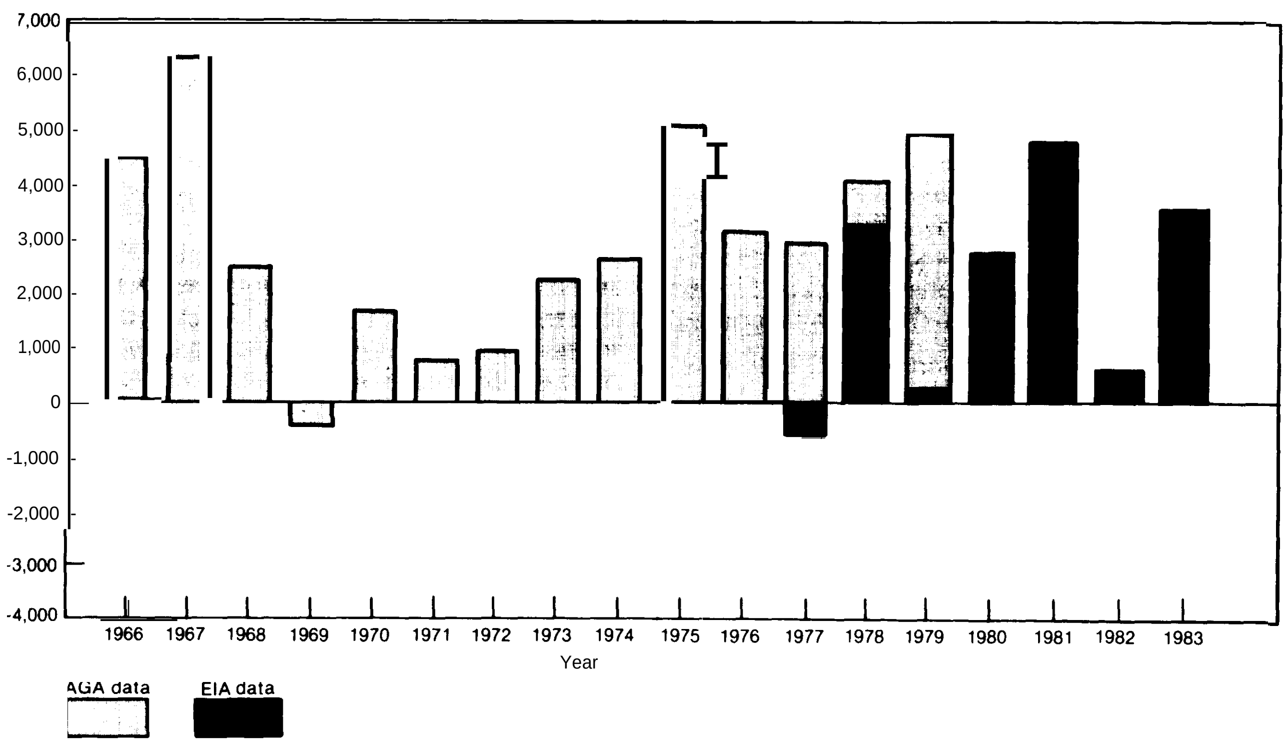
An argument can be made that the historical record, erratic as it seems, supports the idea of generally positive revisions in the long term. This is based on the view that the large but localized negative revisions of the 1970s appear to have ended. The trends in revisions for the areas **outside** the source area for the negative revisions seem far more positive.[5] For example, if the gulf coast revisions were subtracted from the total Lower 48 revisions, as shown in figure 21, the "amended revisions" would appear to support a projection of positive future revisions. On the other hand, an examination of the sources of revisions indicates that extreme caution should be used in forecasting the direction of future revisions.

Of the seven sources of revisions listed previously, the second and seventh are essentially random. The others either will always yield positive revisions, will always yield negative revisions, or may have a bias in one direction or the other. The first source, drilling and production experience, would be random if there were no incentives to be either pessimistic or optimistic in reserve calculations. However, the requirement to raise capital for field development or to meet minimum reserve requirements for a new pipeline are powerful incentives for optimistic reserve estimates. A tendency toward optimistic estimates would result in mostly negative revisions from drilling and production experience. The large

[4] Ibid.

[5] T. J. Woods, "On Natural Gas Trend s," Gas Research Institute, 1982; R. Nehring, contractor report to OTA, op. cit.

**Figure 21.—Additions to Lower 48 Natural Gas Proved Reserves: Revisions As Amended,[a] 1966-83 (BCF)**




aNOTE: EIA plots are for revisions + adjustments and corrections.

SOURCE: Off Ice of Technology Assessment negative revisions of the 1970s in the gulf coast and adjacent provinces appear to have resulted from just such a tendency.

The fifth source, changes in production economics, also could be random in that gas prices could rise faster (yielding positive revisions) or slower (negative revisions) than the costs of operating fields and enhancing production. Although rigid price controls or the competition of low-priced alternative fuels could conceivably lead to negative revisions from this source, it seems more likely that most such revisions would be positive, especially if gas becomes scarcer. In support of this argument, the growth in reserves attributed to well reworking, infill drilling, and lowered abandonment pressures–growth that would be reported as positive revisions—is seen by some analysts as an extremely important component of future reserve additions (see ch. 4, section on "New Gas From Old Fields").

Of the remaining sources of revisions, the third and fourth will always yield positive revisions, and the sixth always will yield negative revisions. *

The confusing mix of "positive," "negative," and "random" sources of revision make it extremely difficult to predict how revisions will behave in the future. Also, revisions data do not indicate which previous years' data are being revised. Consequently, it is difficult to know the causes of past revisions—a necessary prerequisite for intelligent forecasting. For these reasons, some analysts disregard revisions entirely in their trend analyses and implicitly assume they will not be a significant component of future reserve additions.

A reasonable range of average yearly revisions for the next 10 to 15 years appears to be O to 2 TCF/yr, with the positive tendency based on OTA's belief that there may be some significant potential from the growth of older fields due to lowered abandonment pressures, infill drilling, and the like.

*The sixth, knowledge gained from extension tests, yields only negative revisions because an increase in reserves caused by this source would be reported as an extension.

## Reserves-to-Production Ratio

Because the reserves-to-production ratio, (R/P), measures the rate at which gas is produced from discovered reservoirs, it represents the analytical link between projections of new discoveries and forecasts of gas production.

### Factors Affecting R/P

At the level of the individual production firm, the selection of a production rate—and, consequently, the selection of the R/P–represents an economic tradeoff between the cost of drilling additional wells and installing additional gas gathering and processing facilities (i.e., the cost of increasing production), on the one hand, and the cost of holding reserves in the ground, on the other. Consequently, factors such as exploration and development costs, present and expected future gas prices, and interest rates all affect the R/P. For example, increases in current prices will theoretically lead to faster production, while expectations of real increases in future prices can cause production to be delayed.[6]

In oil production, it is well known that too fast a production rate—too low an R/P—can cause a premature decline in production and a loss of potentially recoverable reserves. For example, in a reservoir whose pressure is supplied mainly by water that displaces the oil as it is produced (a "water-drive" reservoir), an overly rapid rate of production can cause the encroaching water to flow around less permeable sections of the reservoir, leaving behind the oil in these sections. When the water reaches the well, the added costs of water separation and disposal can cause premature abandonment.[7]

Because gas flows more easily than oil, there is far more leeway in gas production, and production rates frequently can vary over a wide range. There are, however, the same kinds of physical limits to gas production as to oil production. Although some loss of ultimately recoverable gas from the well may be acceptable to the

[6]Douglas Boh i and Michael Toman, "Understanding Nonrenewable Resource Supply Behavior, " *Science, vol.* 219, Feb. 25, 1983.

7P. A. Stockil (cd.), *Our Industry Petroleum* (London: British Petroleum Co. Ltd., 1977).

producer in exchange for a more rapid payback (from the higher flow rate), the potential for large losses will serve to limit flow rates.

Aside from the obvious economic factors and physical limitations to avoid resource loss, several other factors affect R/P:

- **Technology .–The major technology affecting R/P may be rock-fracturing methods. The use of massive hydraulic fracturing and other fracturing techniques can open** up low-permeability rock and cause marginal wells with low flow rates to become rapid producers. The availability of sophisticated seismic exploratory techniques has reduced overall drilling costs—enhancing the incentive to drill additional wells to expand production–by increasing the success ratio; it also has helped improve the placement of successful wells to maximize production.
- Geology.–The rate of gas flow is directly dependent on the permeability of the gas reservoir formation and on its pressure and thickness. Although fracturing can partly compensate for low permeability, wells in tight gas formations generally produce much more slowly than do wells in more permeable rock because the fractures do not reach all of the tight reservoir rock. Similarly, gas in deep over-pressure formations will for short periods of time produce far more rapidly than in shallow, low-pressure formations; * in fact, the high pressures in such formations have caused severe technical problems in fields such as the Fletcher Field in southwestern Oklahoma, where wells and drilling equipment have been destroyed by failure to control the enormous pressures built up deep undergrounds Also, field size distributions may affect R/P because smaller fields, which will be of increasing importance in future reserve additions, may be produced faster than large, complex fields.
- **Field Maturity .–Early** in a field's lifetime, R/Ps are typically very high because the major focus is on reserve delineation rather than development; during this period, pipeline and gas processing capacity may be nonexistent or minimal and markets may be undeveloped, As pipeline capacity is added and sales contracts signed, the R/P will decrease rapidly. As the field tends toward depletion, the R/P may rise again as gas pressures drop and as drilling gravitates to the marginal, low-permeability formations. However, because the R/P will equal 1.0 in the last year of a field's production, the R/P will decrease during the very last years of the field.
- **Conservation Regulations.–Some gas-**producing States directly regulate production-related variables such as well spacing and flow rates. These regulations are intended to promote efficient development of reserves to prevent loss of ultimate recovery. Their origin lies in the disruption caused by the discovery of the east Texas field in 1930 and the large over supply and resulting wasteful gas production practices that followed.[9]
- **Market Demand.–When the market is demand-limited (deliverability exceeds demand), as it is today, the R/P no longer provides a measure of gas production capacity. Low demand can raise the** R/P.
- **Reserve Requirements.-The substantial cap**ital requirements of gas transmission and distribution systems has led the transmission and distribution companies as well as Government regulatory agencies to pursue long-term contracts requiring high R/Ps and high reserve requirements for pipeline approvals. These requirements do not apply, however, to mature areas where pipeline capacity is already in place.

## Historical Variation of R/P*

The early years of gas discovery in this country were marked by lack of a gas distribution network, substantial discoveries of gas as a low-valued or even unwanted byproduct of oil ex-

*However, once the "propping effect" of the gas under pressure is removed by partial production, the permeability of the reservoir may be reduced to "tight gas" levels, and production will slow.

[8] 'Fletcher Area Underscores Perils in Deep Gas Reservoirs, " *Oil and Gas Journal,* Feb. 7, 1983, p. 25.

[9] R. E. Megill, *An Introduction to Exploration Economics* (Tulsa, OK: Petroleum Publishing Co., 1971 ).

*Based on Jensen Associates, inc., *Understanding Natural Gas Supply in the U. S.,* April 1983, contractor report to OTA.

ploration, and the eventual discovery of enormous reserves (e.g., the 1922 discovery of the giant Hugoton field in Kansas) that overwhelmed existing demand. The combination led to very high R/Ps in the 1920-40 period, followed by an era of continued decline.

In the early years of the post-world War II growth, as new pipeline systems were constructed, previously unproductive proved reserves were developed. This activity increased the level of production without adding substantially to the volume of proved reserves, thus lowering the R/P. Later in the 1960s and 1970s, when the natural gas market had become supply constrained, production was again maintained by further development and a lowering of the R/P. At this time, however, the ability to obtain greater production from a given volume of proved reserves was improved by a geographical shift in production to the Gulf of Mexico and encouraged by economic changes that favored more rapid extraction rates.

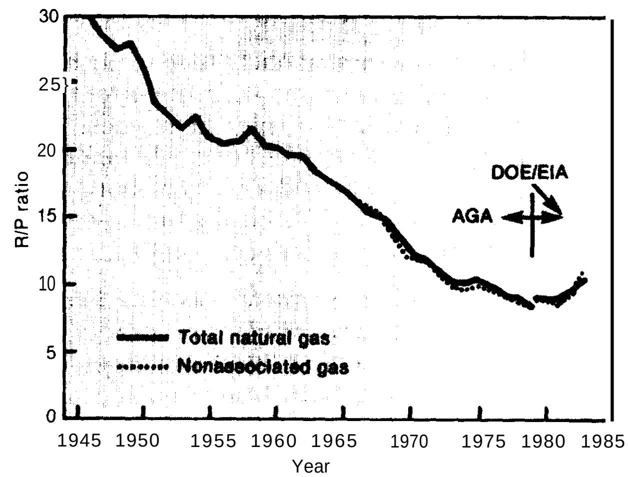
The decline in the R/P from 1946 to 1983 for the Lower 48 States is shown in figure **22. The AGA data cover the period 1946 through 1979, while DOE/EIA includes** only the **7** years from 1977 through 1983. *

The AGA data show strong year-to-year declines in the R/P over virtually the entire 34-year period of available data. Recently, the rate of decline eased from an average of over 0.8 per year between 1966 and 1974, to an average of 0.5 per year during the 1975-79 period. DOE/EIA estimated dry gas data show a further easing of the decline rate to about 0.2 per year between 1977 and 1981, and an actual increase in R/P thereafter due to the weak markets for gas and relatively strong reserve replacements during 1981-83.

Currently, the lowest R/P for the nonassociated gas of a major producing State is 8.4 in Louisiana. The lowest R/P for any geographical subdivision published by the DOE/EIA reserves report was a 5.0 for the State domain of the Texas offshore

* *These displayed ratios are developed using the year-end reserves estimate for the year prior to the production period. This approach to calculating the R/P stems from a belief that production in a given year is more likely to be representative of reserves that are available at the beginning of the year.

**Figure 22.— Reserve-to-Production Ratios for Natural Gas in the Lower 48 States**




SOURCES: Office of Technology Assessment, based on data from Energy information Administration, U.S. *Crude Oil, Natural Gas, and* Natural Gas *Liquids Reserves— 1983 Annual Report, DOE/EI-0216 (63),* October 1964, and American Petroleum Institute, American Gas Association, and Canadian Petroleum Association, *Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States and Canada as of December 31, 1979, vol. 34,* June 1980,

(for 1982). The total Texas and Louisiana offshore, representing about one-third of Lower 48 State production, stood at 6.5 in 1981 and 8.4 in 1983. With the Gulf of Mexico excluded, the balance of the Lower 48 States had a 1981 R/P of 9.8 and a 1983 R/P of 11.7. Contrasting strongly with the lower R/Ps of the gulf coast would be that of 26.3 for the heavily depleted reservoirs of Kansas and 23.6 in Wyoming, where field development for newly discovered reserves was incomplete in 1983.

## Implications

These recent examples of R/Ps for different areas of the United States may indicate that the Lower 48 State R/P could move further downward in future years if gas supplies were found in areas with combinations of high reservoir permeabilities and economics that favor extensive field development. * This is in fact what happened throughout the 1970s as the Gulf of Mexico be-

*Some opinion exists, however, that some of the lower R/Ps are due to underreporting of reserves rather than to extremely rapid production. If true, this might indicate less potential for further lowering the national R/P.

came an increasingly large component of the total supply. Between 1973 and 1981 the Gulf's share of production grew from 20 to 33 percent.

An additional factor that might tend to push the R/P downwards is a continuation of current discovery trends towards smaller field sizes. It is widely believed that smaller fields will be delineated, developed, and produced over shorter periods of time than was historically the case with the mix of field sizes discovered until now.

On the other hand, some factors could cause the R/P to climb upward. Future production trends may tend to increase the shares of gas from tighter, lower permeability reservoirs and other sources more expensive to develop, which could lead to slow rates of production from proved reserves. For example, both the deep Tuscaloosa trend and the Western Overthrust Belt are expected to have relatively high R/Ps; field development and gas processing costs for these areas are too high to allow rapid depletion at current gas prices.[10] in addition, the R/P might tend to increase if future reserve additions were below annual production rates because the production capability (as a percentage of remaining reserves) of reservoirs tends to decline with their age, * and a rate of reserve additions that is below replacement levels will lead to an increasing average age for U.S. gas reservoirs.[11]

It is important to note that the balance between demand and supply will also play a critical role in determining the R/P. Because the purpose of this evaluation is to examine the potential for gas supply **if gas is highly sought after, gas production–and, consequently** R/P—is assumed to be based on a supply-limited situation. * * This situation would tend to intensify the incentives to develop fields rapidly and to maximize production (minimize R/P). Rapid field development should not be expected, however, if the current gas "bubble" of oversupply continues. In this case, field development and production are likely to be slowed.

In conclusion, expected R/Ps in 15 to 20 years may range from values below recent (pre-bubble) levels–perhaps 7.0, or even somewhat lower–to levels slightly higher–perhaps 9.5. Part of the future trend will be caused by the geologic nature of new discoveries and their geographic environment. These factors can be manipulated somewhat but are more likely to be imposed by the random success of future exploration. Because the R/P is also strongly affected by the willingness to drill development wells and to take other (expensive) production-enhancing measures, large increases in gas prices would tend to drive the R/P down to its lower limit. The lower value obviously can occur only with high gas demand, an assumption of this study. If gas demand were poor, the R/P could exceed 9.5 for a while. Eventually, however, the lack of exploration incentives would move proved reserves back into balance with production requirements.

## Production Scenarios

Table 18 summarizes the ranges of reserve additions and R/Ps projected for Lower 48 natural

[10] E F Hardy and C. P. Neill, testimony to the Subcommittee on Fossil and Synthetic Fuels, Committee on Energy and Commerce, U.S. House of Representatives, June 1, 1981.

*Up to a point. During the last few years of a reservoir's life, its R/P must decrease because, in the last year, it will be 1.0. The last year's production will use up the entire remaining reserve.

[11] I bid.

* *That is, a situation where additional supplies at prevailing prices would be easily absorbed,

**Table 18.-Summary of Projections of Components of Reserve Additions and R/Ps**

| | | |
|---|---|---|
| New field discoveries | 1985-86 | 2.0-3.5 TCF/yr |
| | 1987-2000 | 1.5-3.5 TCF/yr |
| Extensions and new pool discoveries | 1985-86 | 8.0-12 TCF/yr |
| | 1987-2000 | 6.0-11 TCF/yr |
| Revisions | 1985-2000 | 0-2.0 TCF/yr |
| R/P | **2000** | **7.0-9.5** |
| Scenario 1A: reserve additions | 1985-86 | 17.5 TCF/yr |
| | 1987-2000 | 16.5 TCF/yr |
| R/P | 2000 | 7.0 |
| Scenario 1 B: reserve additions | 1985-86 | 10.5 TCF/yr |
| | 1987-2000 | 7.5 TCF/yr |
| R/P | 2000 | 9.5 |

SOURCE Office of Technology Assessment.

gas development. Tables 19 and 20 present production and reserves projections that represent the two extremes of the ranges in table 18. The first projection assumes an optimistic exploration future and rapid production of newly found reserves-predicated upon high gas prices, high demand, and an avoidance of large reserve additions in low permeability areas that are hard to develop rapidly. The second projection assumes low finding rates and an increase in low permeability reserves where production rates are limited. Because each projection represents a convergence of events of relatively low probability—e.g., the lowest rates of new field discoveries, extensions and new pool discoveries, zero revisions, and an upturn in R/P-the projections should be viewed as approximately bounding the range of production and proved reserve levels, rather than as identifying likely values.

**able 19.–Lower 48 States Natural Gas Production and Reserves 1981.2000 (in TCF)**
**SCENARIO 1A: Optimistic Exploration, Rapid Production**

| Year | Production | Reserve additions | Proved reserves | R/P[a] |
|---|---|---|---|---|
| 1981 (actual) | 18.5 | 21.5 | 168.6 | 9.0 |
| 1982 (actual) | 17.2 | 15.1 | 166.5 | 9.8 |
| 1983 (actual) | 15.5 | 15.0 | 166.0 | 10.7 |
| 1984 | 16.0 | 15.0 | 165.0 | 10.4 |
| 1985 | 18.0 | 17.5 | 164.5 | 9.2 |
| 1986 | 18.3 | 17.5 | 163.7 | 9.0 |
| 1987 | 18.6 | 16.5 | 161.6 | 8.8 |
| 1988 | 18.8 | 16.5 | 159.3 | 8.6 |
| 1989 | 19.0 | 16,5 | 156.8 | 8.4 |
| 1990 | 18,9 | 16,5 | 154.4 | 8.3 |
| 1991 | 18.8 | 16.5 | 152.1 | 8.2 |
| 1992 | 18.8 | 16.5 | 149.8 | 8.1 |
| 1993 | 18.7 | 16.5 | 147.6 | 8.0 |
| 1994 | 18.9 | 16.5 | 145.2 | 7.8 |
| 1995 | 18.9 | 16.5 | 142.8 | 7.7 |
| 1996 | 18.8 | 16.5 | 140.5 | 7.6 |
| 1997 | 18.7 | 16,5 | 138.3 | 7.5 |
| 1998 | 18.7 | 16.5 | 136.1 | 7.4 |
| 1999 | 18.6 | 16.5 | 134.0 | 7.3 |
| 2000 | 18.6 | 16.5 | 131.9 | 7.2 |
| Cumulative production after 1982 = 330,6 = 42%0 of USGS remaining resource. | | | | |

aR/p calculatedby dividing previous year's (year end) reserves by production in the listed Year

SOURCE Off Ice of Technology Assessment,

**Table 20.– Lower 48 States Natural Gas Production and Reserves 1981.2000 (in TCF)**
**SCENARIO 1 B: Pessimistic Exploration, Slowed Production**

| Year | Production | Reserve additions | Proved reserves | R/P[a] |
|---|---|---|---|---|
| 1981 (actual) | 18.5 | 21.5 | 168.6 | 9.0 |
| 1982 (actual) | 17.2 | 15.1 | 166.5 | 9.8 |
| 1983 (actual) | 15.5 | 15.0 | 166.0 | 10.7 |
| 1984 | 16.0 | 15.0 | 165.0 | 10.4 |
| 1985 | 18.0 | 10,5 | 157.5 | 9.2 |
| 1986 | 17.3 | 10.5 | 150.7 | 9.1 |
| 1987 | 16.6 | 7.5 | 141.6 | 9.1 |
| 1988 | 15.6 | 7.5 | 133.5 | 9.1 |
| 1989 | 14.5 | 7.5 | 126.0 | 9.2 |
| 1990 | 13.7 | 7.5 | 119.8 | 9.2 |
| 1991 | 13.0 | 7.5 | 114.3 | 9.2 |
| 1992 | 12.3 | 7.5 | 109.5 | 9.3 |
| 1993 | 11.8 | 7.5 | 105.2 | 9.3 |
| 1994 | 11.3 | 7.5 | 101.4 | 9.3 |
| 1995 | 10.8 | 7,5 | 98.1 | |
| 1996 | 10.4 | 7.5 | 95.2 | 9.4 |
| 1997 | 10.1 | 7.5 | 92.6 | 9.4 |
| 1998 | 9.8 | 7.5 | 90.3 | 9.5 |
| 1999 | 9.5 | 7.5 | 88.3 | 9.5 |
| 2000 | 9.3 | 7.5 | 86.5 | 9.5 |
| Cumulative production after 1982 = 236TCF = 310/o of USGS remaining resource. | | | | |

aR/P calculated by dividlng previous year's (year end) reserves by production In the listed Year

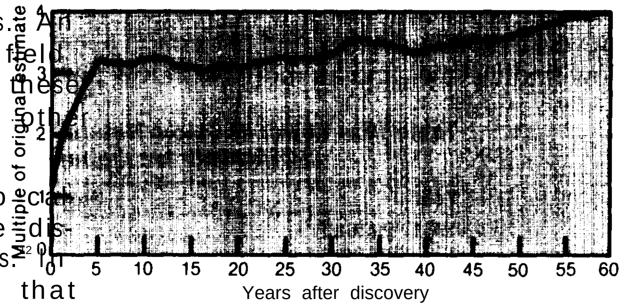
SOURCE Office of Technology Assessment

# APPROACH NUMBER 2–PROJECTING NEW POOL DISCOVERIES, EXTENSIONS, AND REVISIONS AS A SINGLE GROWTH FACTOR

The preceding approach is designed to allow a projection of future gas reserves based on separate estimates of new field discoveries, extensions, new pool discoveries, and revisions.[12] An alternative method is to project only new field discoveries and apply a "growth factor" to these discoveries that combines the effects of the other three categories of reserve additions.

USGS has used a field growth approach to calculate the amount of gas remaining to be discovered in the inventory of identified fields.[12] In that application, a curve was constructed that describes the reserve growth in initial discoveries that occurs after the year of discovery, averaged over all discovered fields nationwide and over 9 of the 14 discovery years where appropriate data were available (1966-79). This curve, illustrated in figure 23, shows a 60-year growth in reserves to about four times the initial (discovery year) estimate of gas volumes discovered. The curve shows that most of this growth occurs in the first 5 years after the discovery year. In the USGS calculation, the curve was applied to the initial discoveries reported in **every** discovery year, assuming that reserve growth patterns of recently discovered fields would be the same as the patterns of much older discoveries. The gas volumes calculated in this manner—gas that is difficult to classify as discovered or undiscovered–are called "inferred reserves" by USGS.

**Figure 23.-The Growth of Year-of-Discovery Estimates of the Amount of Recoverable Natural Gas Discovered in the Lower 48 States**




SOURCE: D. H. Root, "Estimation of Inferred Plus Indicated Resevees for the United States," app. F in Estimates of *Undiscovered Recoverable Conventional Resources of Oil and Gas in the United States,* U.S. Geological Survey Circular 860, 1981.

This method may be extended to project how the first-year estimates of reserve additions from future new field discoveries will grow in the years following the discovery year. However, certain adjustments have to be made. First, a growth factor calculated by tracking "initial discoveries" data must be increased if it is to apply directly to **new field discovery data. This is because the discovery data[13] includes not only new field** discoveries, but also "certain hydrocarbon accumulations which are significant from the standpoint that advances in exploration technology resulted in the discovery of such reservoirs.[14] Consequently, the year-of-discovery values are larger than those of "new field discoveries," and the later expansion is lower because some technology-based expansions are excluded. Adjusting the calculated growth factor to account only for growth of new fields may raise the factor by about 20 percent.[15]

Second, for the method to be credible, the assumption that the historical growth curve will continue to be valid must be relaxed somewhat. Many of the factors affecting the growth of recoverable reserves in newly discovered fields have changed; consequently, it appears likely that the growth curve has changed as well. The development of a credible forecasting procedure depends on defining a new curve or family of curves that logically fit these changed conditions.

Table 21 lists the arguments–some speculative—that support an increase or decrease (over historical levels of field growth) in the ultimate magnitude of reserve growth in new fields. *

[12] U.S. Geological Survey Circular 860, app. F.

[13] The data came from table XIV of *Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States and Canada,* vols. *21-34,* 1966 through 1979, American Gas Association/American Petroleum Institute/Canadian Petroleum Association.

[14] Ibid.

[15] Robert Paszkiewicz, Jensen Associates, personal communication.

*These conditions are the same as those affecting revisions, extensions, and new pool discoveries.

**Table 21.-Arguments[a] for the Question, "Will the Reserve Growth in New Fields Be Larger or Smaller Than the Growth Recorded in Previously Discovered Fields?"**

A. New ***fields will grow more:***

1. Recent increases in real gas prices are leading to greater recovery factors for gasfields—from closer spacing of development wells, extensions into less-permeable margins of reservoirs, exploitation of smaller pools, lowering of abandonment pressures, and reworking of older wells. Together, they increase the ultimate recovery (reported cumulative production at field abandonment).
2. The historical growth factor does not accurately reflect the actual field growth, The large negative revisions in onshore south Louisiana and Texas have artificially depressed reported field-growth rates. Because these revisions were due to a unique set of circumstances, they are unlikely to recur, and reported growth rates should increase.

B. New ***fields will grow less:***

1. Part of the reason that the levels of new field discoveries reported by EIA were higher than those reported by AGA during the 3 years the two reports overlapped is probably that EIA reported reserve additions during the discovery year that AGA did not report until the second year. Therefore, when EIA-reported trends are used to project future new field discoveries, the growth factor used should be smaller than the historical average, which was derived from AGA data.
2. The historical growth factor was derived from data developed during a time when giant gasfields dominated gas reserves. Giant fields with multiple pools take many years to develop and are generally believed to have greater relative growth than small fields. Present and future field sizes will be smaller and should be expected to have smaller growth factors and faster development.
3. Improvements in seismic and other exploration technology, as well as in reservoir engineering, allow clearer initial delineation of field boundaries and other field characteristics and more accurate first-year reserve estimates. This should leave less room for growth.
4. Increased gas prices have led to acceleration of field development. Some of the development that might previously have taken place in the second year now takes place in the first year and is reported as part of the initial new field discovery reserve data.
5. High capital requirements to develop new fields in hostile environments—an increasing feature of today's resource base—require a more accurate first-year estimate of reserves, leading to lower "growth" later on.

aSome of these arguments are speculative. For example, in B.1., OTA has not determined the cause of the AGA/EIA differences in reported new field discoveries.

SOURCE Office of Technology Assessment

USGS's **estimate is not the only available estimate of field growth. Table 22 presents three other estimates, with ultimate growth ranging from 3,5 to 6.3 times the initial year-of-discovery estimate.**

**In order to use the "growth factor" approach to project future gas production, Jensen Associ**ates, Inc., an OTA contractor, constructed a simple model that applied growth curves similar to that in figure 23 to both known fields and to projected levels of new field discoveries. A growth curve that reached a factor of 4.0 in 60 years was applied to all pre-1982 **discoveries, while** curves with 30-year growth periods were applied to discoveries from 1982 on. The period of 30 years was selected to reflect OTA's belief that the pace of field development has quickened. The choice is a guess because data sufficient to calculate a new timetable are not available. The uncertainty in the ultimate value for the growth factor is reflected in a range of values from **3.0 to 5.0. In OTA's** opinion, 5.0 represents an optimistic upper-bound on future growth in new fields.

Tables 23 through 25 present the results of three scenarios representing the search for reasonable upper- and lower-bounds on future gas

**Table 22.—Alternative Estimates of Growth Factors for Initial Reserve Estimates for Gasfields**

| Author | Suggested growth factors |
|---|---|
| 1. USGS (Root) (1981) , . | 4.0, all fields |
| 2. Haun (1981) . . . . . . . . . | 4.0, fields younger than 48 years |
| | 5.0, fields older than 48 years |
| 3. Hubbert (1974) . . . . . . | 3,5, all fields |
| 4. Marsh (1971) . . . . . . . . | 5.0, fields younger than 28 years |
| | 6.3, fields older than 28 years |

1. D. H. Root, "Estimation of Inferred Plus Indicated Reserves for the United States," app. F in G L. Dolton, et al , Estimates of *Undiscovered* Recoverable *Conventional Resources of Oil and Gas in the United States,* U S Geological Survey Circular 660, 1981,
2. J D. Haun, "Future of Petroleum Exploration in the United States," *AAPG Bulletin 656(10), 1981.*
3. M. K. Hubbert, "U S, Energy Resources, A Review as of 1972, " S Res 45, ser. No. 93-40 (92-75), Committee on Interior and Insular Affairs, U S Senate, 1974, cited in Haun, ibid.
4. G. R. Marsh, "How Much Oil Are We Really Finding, " Oil *and Gas Joumal,* Apr 5, 1971, cited in Haun, op cit.

SOURCE: Office of Technology Assessment

production. * For each scenario, the "growth curve" methodology was applied only to non-associated gas. Associated gas was projected separately by applying a gas-to-oil production ratio of 1.3 MCF per barrel of crude oil to the ElA's 1981 oil production forecast.[16]

*The production projections in the three tables should be viewed as slightly pessimistic. This is because they were based on projected 1982 nonassociated reserve additions of 8.7-10.2 TCF, whereas actual 1982 additions were about 14 TCF.

[6]U.S. Department of Energy, 1981 *Annual Report to Congress*, vol. 3, p. 62.

**Table 23.–Lower 48 States Natural Gas Production and Reserves, 1982-2000 (in TCF)-Scenario 2A: Very Optimistic[a]**

| Year | Total gas production | Nonassociated gas Production | Reserve additions | Proved reserve | R/P | Assoc./dissolved gas[b] production |
|---|---|---|---|---|---|---|
| 1982 | 18.7 | 15.7 | 10.2 | 132.8 | 8.8 | 3.0 |
| 1983 | 18.2 | 15.3 | 11.7 | 129.2 | 8.7 | 2.9 |
| 1984 | 18.0 | 15.2 | 13.0 | 127.0 | 8.5 | 2.9 |
| 1985 | 18.0 | 15.2 | 14.8 | 126.6 | 8.3 | 2.8 |
| 1986 | 18.3 | 15.5 | 15.5 | 126,7 | 8.2 | 2.8 |
| 1987 | 18.6 | 15.8 | 15.8 | 126.6 | 8.0 | 2.7 |
| 1988 | 18.9 | 16.2 | 15.9 | 126,3 | 7.8 | 2.7 |
| 1989 | 19.3 | 16.5 | 16.0 | 125.7 | 7.6 | 2.7 |
| 1990 | 19,5 | 16.8 | 16.0 | 124.9 | 7.5 | 2.7 |
| 1991 | 19.7 | 17.1 | 16.1 | 123.9 | 7.3 | |
| 1992 | 19.8 | 17.3 | 16.2 | 122.8 | 7.2 | 2.6 |
| 1993 | 19.8 | 17.3 | 16.2 | 121.7 | 7.1 | 2.5 |
| 1994 | 19.7 | 17.2 | 16.3 | 120.8 | 7.1 | 2.5 |
| 1995 | 19.6 | 17.2 | 15.3 | 119.0 | 7.0 | 2.4 |
| 1996 | 19.3 | 16.9 | 15.4 | 117.4 | 7.0 | 2.4 |
| 1997 | 19.1 | 16.8 | 15.4 | 116.0 | 7.0 | 2.4 |
| 1998 | 19.0 | 16.6 | 15.4 | 114.8 | 7.0 | 2.3 |
| 1999 | 18.8 | 16.5 | 15.5 | 113.8 | 7.0 | 2.3 |
| 2000 | 18.7 | 16.4 | 15.5 | 112.9 | 6.9 | 2.3 |

Cumulative production after 1982 = 342.4 TCF = 44°/0 USGS remaining resource.

Note: Rows and columns may not add exactly due to rounding.
aAssumptions: Nonassociated gas new field discovery rate ˚3,000 BCF/yr
Growth factor = 5.0
Additional growth from price rises for old gas = 1000 BCF/yr from 1985 to 1995.
bAssociated/dissolved gas–gas found in the same reservoir with oil.

SOURCE: Jensen Associates, Inc., contract submission to the Office of Technology Assessment, 1983.

## APPROACH NUMBER 3–REGION-BY-REGION REVIEW OF RESOURCES AND EXPLORATORY SUCCESS**

Using a region-by-region review to project future gas production involves a geologist's examination of a variety of factors affecting production in 10 individual regions of the Lower 48 States and his subjective evaluation of their future production potential.

Fc]r this approach, the gas resource base was assumed to be a compromise between the assessments of USGS and PGC. For each region, a resource value was selected by examining the field size and number implications of the two assessments and choosing the value that seemed more

**The analysis described in this section was performed by Joseph P. Riva, Jr., Specialist in Earth Sciences, Congressional Research Service (CRS).

## Table 24.–Lower 48 States Natural Gas Production and Reserves, 1982.2000 (in TCF)– Scenario 2B: Pessimistic[a]

| Year | Total gas Production | Nonassociated gas Production | Reserve additions | Proved reserve | R/P | Assoc./dissolved gas[b] production |
|---|---|---|---|---|---|---|
| 1982 . . . . . . . . . . . . . . . . . . . . | 18.7 | 15.7 | 8.7 | 131.3 | 8.8 | ***3.0*** |
| 1983 . . . . . . . . . . . . . . . . . . . . | 18.0 | 15.1 | 8.4 | 124.6 | 8.7 | ***2.9*** |
| 1984 . . . . . . . . . . . . . . . . . . . . | 17.4 | 14.6 | 8.3 | 118.4 | 8.5 | ***3.0*** |
| 1985 . . . . . . . . . . . . . . . . . . . . | 16.9 | 14.1 | 8.3 | 112.6 | 8.4 | ***2.8*** |
| 1986 . . . . . . . . . . . . . . . . . . . . | 16.4 | 13.6 | 8.2 | 107.2 | 8.3 | ***2.8*** |
| 1987 . . . . . . . . . . . . . . . . . . . . | 15.9 | 13.2 | 7.6 | 101.7 | 8.1 | ***2.7*** |
| 1988 . . . . . . . . . . . . . . . . . . . . | 15.4 | 12.7 | 7.6 | 96.6 | 8.0 | ***2.7*** |
| 1989 . . . . . . . . . . . . . . . . . . . . | 15.0 | 12.3 | 7.7 | 92.0 | 7.9 | ***2.7*** |
| 1990 . . . . . . . . . . . . . . . . . . . . | 14.6 | 11.9 | 7.7 | 87.7 | 7.7 | ***2.7*** |
| 1991 . . . . . . . . . . . . . . . . . . . . | 14.2 | 11.6 | 7.7 | 83.8 | 7.6 | ***2.6*** |
| 1992 . . . . . . . . . . . . . . . . . . . . | 13.8 | 11.2 | 7,7 | 80.3 | 7.5 | ***2.6*** |
| 1993 . . . . . . . . . . . . . . . . . . . . | 13.4 | 10.9 | 7.7 | 77.1 | 7.4 | ***2.5*** |
| 1994 . . . . . . . . . . . . . . . . . . . . | 13.0 | 10.5 | 7.7 | 74.4 | 7.3 | ***2.5*** |
| 1995 . . . . . . . . . ........! . . . | 12.6 | 10.2 | 7.2 | 71.4 | 7.3 | ***2.4*** |
| 1996 . . . . . . . . . . . . . . . . . . . . | 12.2 | 9.8 | 7.2 | 68.8 | 7.3 | 2.4 |
| 1997 . . . . . . . . . . . . . . . . . . . . | 11.8 | 9.5 | 7.1 | 66.5 | 7.3 | 2.4 |
| 1998 . . . . . . . . . . . . . . . . . . . . | 11.5 | 9.2 | 7.1 | 64.4 | 7.2 | 2.3 |
| 1999 . . . . . . . . . . . . . . . . . . . . | 11.2 | 8.9 | 7.1 | 62.6 | 7.2 | 2.3 |
| 2000 . . . . . . . . . . . . . . . . . . . . | 11.0 | 8.7 | 7.1 | 61.0 | 7.2 | 2.3 |

Cumulative production after 1982 = 254 TCF = 330/0 USGS remaining resource.

Note Rows and columns may not add exactly due to rounding.
aAssumptions: Nonassociated gas new field discovery rate = 1500 BCF/yr
Growth factor = 4.0
Additional growth from price rises for old gas = 500 BCF/yr from 1985 to 1995.
bAssocla{ed/dissolved gas—gas found in the same reservoir with oil

SOURCE. Jensen Associates, Inc, contract submission to the Office of Technology Assessment, 1983

## Table 25.–Lower 48 States Natural Gas Production and Reserves,1982.2000 (in TCF)– Scenario 2C: Very Pessimistic[a]

| Year | Total gas production | Nonassociated gas Production | Reserve additions | Proved reserve | R/P | Assoc./dissolved gas[b] production |
|---|---|---|---|---|---|---|
| 1982 . . . . . . . . . . . . . . . . . . . . | 18.5 | 15.5 | 8.7 | 131.3 | 8.9 | ***3.0*** |
| 1983 . . . . . . . . . . . . . . . . . . . . | 17.7 | 14.8 | 8.0 | 124.7 | 8.9 | ***2.9*** |
| 1984 . . . . . . . . . . . . . . . . . . . . | 16.9 | 14.0 | 7.5 | 118.1 | 8.9 | ***2.9*** |
| 1985 . . . . . . . . . . . . . . . . . . . . | 16.1 | 13.3 | 6.4 | 111.2 | 8.9 | ***2.8*** |
| 1986 . . . . . . . . . . . . . . . . . . . . | 15.3 | 12.5 | 6.1 | 104.9 | 8.9 | ***2.8*** |
| 1987 . . . . . . . . . . . . . . . . . . . . | 14.5 | 11.8 | 5.4 | 98.5 | 8.9 | ***2.7*** |
| 1988 . . . . . . . . . . . . . . . . . . . . | 13.8 | 11.1 | 5.4 | 92.8 | 8.9 | ***2.7*** |
| 1989 . . . . . . . . . . . . . . . . . . . . | 13.1 | 10.4 | 5.4 | 87.9 | 8.9 | ***2.7*** |
| 1990 . . . . . . . . . . . . . . . . . . . . | 12.5 | 9.9 | 5.5 | 84.4 | 8.9 | ***2.7*** |
| 1991 . . . . . . . . . . . . . . . . . . . . | 12.0 | 9.4 | 5.5 | 79.6 | 8.9 | ***2.6*** |
| 1992 . . . . . . . . . . . . . . . . . . . . | 11.5 | 8.9 | 5.5 | 76.1 | 8.9 | ***2.6*** |
| 1993 . . . . . . . . . . . . . . . . . . . . | 11.1 | 8.6 | 5.5 | 73.1 | 8.9 | ***2.5*** |
| 1994 . . . . . . . . . . . . . . . . . . . . | 10.7 | 8.2 | 5.6 | 70.5 | 8.9 | ***2.5*** |
| 1995 . . . . . . . . . . . . . . . . . . . . | 10.4 | 7.9 | 5.6 | 68.1 | 8.9 | ***2.4*** |
| 1996 . . . . . . . . . . . . . . . . . . . . | 10.1 | 7.7 | 5.5 | 66.0 | 8.9 | ***2.4*** |
| 1997 . . . . . . . . . . . . . . . . . . . . | 9.8 | 7.4 | 5.5 | 64.1 | 8.9 | 2.4 |
| 1998 . . . . . . . . . . . . . . . . . . . . | | 7.2 | 5.5 | 62.4 | 8.9 | 2.3 |
| 1999 . . . . . . . . . . . . . . . . . . . . | 9.3 | 7.0 | 5.5 | 60.9 | 8.9 | 2.3 |
| 2000 . . . . . . . . . . . . . . . . . . . . | 9.1 | 6.8 | 5.5 | 59.6 | 8.9 | 2.3 |

Cumulative production after 1982 = 223.4 TCF = 29% USGS remaining resource.

Note Rows and columns may not add exactly due to rounding
aAssumptions Nonassociated gas new field discovery rate = 1,500 BCF/yr
Growth factor = 30
No additional growth from price rises for old gas
bAssociated/dissolved gas—gas found in the same reservoir with 011

SOURCE Jensen Associates, Inc, contract submission to the Office of Technology Assessment, 1983 realistic. Then, future additions to proved reserves were estimated, based on a subjective evaluation of the following factors:

- **Difficulty and expense of development.–** Based on expected field sizes, depths, known geology.
- Announced leasing schedules.
- "Maturity" of province.–The percent of total expected resources that have already been developed.
- Recent development history .-Especially, the rates of entry into proved reserves of the remaining resources.

For each region, it was generally considered unlikely that a very high percentage of the remaining undiscovered resource—say, 50 percent or greater—could be transferred into proved reserves by 2000, and this situation acted as a strict limit on production in some regions, for example, in the "west Texas and eastern New Mexico' region. * *

Tables 26 and 27 present two scenarios of future gas production and reserve additions based on the above approach. Scenario 3A projects that one-quarter of the gas estimated to be available in undiscovered fields at the end of 1981 will be discovered by 2000. This compares to 55 percent of the undiscovered gas being discovered between 1945 and 1981, a period when larger prospects were available, but also when gas discovery rates may have been hampered by low regulated prices. In this scenario, gas production is projected to increase in the Rocky Mountains and Great Plains region, the Eastern Interior region, and the Appalachian region; in addition, production begins in Oregon-Washington and on the Atlantic continental shelf. However, major production decreases are projected for west Texas and eastern New Mexico, the midcontinent, and the gulf coast, all critical gas producers today.

Scenario 3B assumes that exploration becomes more efficient and that 35 percent of the resources in undiscovered fields can be discovered by 2000. Even under this more optimistic scenario, however, gas production will decline to 13.3 TCF by 2000.

* *To stabilize current gas production to the end of the century in this region, 96 percent of the estimated undiscovered gas in the region would have to be discovered by 2000. From 1970 to 1981, 23 percent of the inferred reserves plus undiscovered resources were added to reserves.

**Table 26.—Lower 48 States Natural Gas Production and Reserves, 1982-2000 (in TCF)—Scenario 3A**

| Year | Production | Reserve additions | Proved reserves | R/P |
|---|---|---|---|---|
| 1981 | 18.5 | 21.6 | 168.6 | 9 |
| 1982 | 18.6 | 10.9 | 160.9 | 9 |
| 1983 | 17.6 | 10.9 | 154.2 | 9 |
| 1984 | 16.8 | 11,2 | 148.5 | 9 |
| 1985 | 16.1 | 11.2 | 143.5 | 9 |
| 1986 | 15,7 | 11.2 | 139.0 | 9 |
| 1987 | 15.3 | 11.2 | 135.0 | 9 |
| 1988 | 15.1 | 11.2 | 131.0 | 9 |
| 1989 | 14.7 | 11.2 | 127.4 | 9 |
| 1990 | 14.5 | 11.2 | 124.1 | 9 |
| 1991 | 14.3 | 11.2 | 121.0 | 8 |
| 1992 | 14.2 | 11.2 | 118.0 | 8 |
| 1993 | 14.0 | 11.2 | 115.2 | 8 |
| 1994 | 13.7 | 10.1 | 111.6 | 8 |
| 1995 | 13.5 | 10.1 | 108.2 | 8 |
| 1996 | 13.4 | 10.3 | 105.1 | 8 |
| 1997 | 13.3 | 10.3 | 102.1 | 8 |
| 1998 | 13.0 | 10.3 | 99.4 | 8 |
| 1999 | 12.8 | 10.3 | 97.0 | 8 |
| 2000 | 12.6 | 10.3 | 94,6 | 8 |

Cumulative production after 1982 = 260.6 = 34°/0 USGS maining resource.

SOURCE: J. P. Riva, Jr., *A Projection of Converrtiona/lNatural Gas Production in the Lower 48 States to the Year 2000,* Congressional Research Service/Library of Congress, June 10, 1983

**Table 27.—Lower 48 States Natural Gas Production and Reserves, 1982-2000 (in TCF)—Scenario 3B**

| Year | Production | Reserve additions | Proved reserves | R/P |
|---|---|---|---|---|
| 1981 | 18.5 | 21.6 | 168.6 | 9 |
| 1982 | 18.7 | 12.1 | 161.9 | 9 |
| 1983 | 18.0 | 12.1 | 156.0 | 9 |
| 1984 | 17.3 | 12.1 | 150.8 | 9 |
| 1985 | 16.8 | 12.1 | 146.1 | 9 |
| 1986 | 16.2 | 12.1 | 142.0 | 9 |
| 1987 | 15.8 | 12.1 | 138.3 | 9 |
| 1988 | 15.4 | 12.1 | 135.0 | 9 |
| 1989 | 15,0 | 12.1 | 132.1 | 9 |
| 1990 | 15.1 | 12.1 | 129.1 | 8.5 |
| 1991 | 15.6 | 12.1 | 125.5 | 8 |
| 1992 | 15.7 | 12.1 | 121.9 | 8 |
| 1993 | 15.2 | 12.1 | 118.8 | 8 |
| 1994 | 14.8 | 12.1 | 116.0 | 8 |
| 1995 | 14.5 | 12.1 | 113.6 | 8 |
| 1996 | 14.2 | 12.1 | 111.5 | 8 |
| 1997 | 13.9 | 12.1 | 109.7 | 8 |
| 1998 | 13.7 | 12.1 | 108.0 | 8 |
| 1999 | 13.5 | 12.1 | 106.6 | 8 |
| 2000 | 13.3 | 12.1 | 105.4 | 8 |

Cumulative production after 1982 = 274 = 35% USGS remaining resource.

SOURCE: J P. Riva, Jr., *A Projection of Conventional Natural Gas Production in the Lower 48 States to the Year 2000,* Congressional Research Service/Library of Congress, June 10, 1983.

# APPROACH NUMBER 4–GRAPHING THE COMPLETE PRODUCTION CYCLE

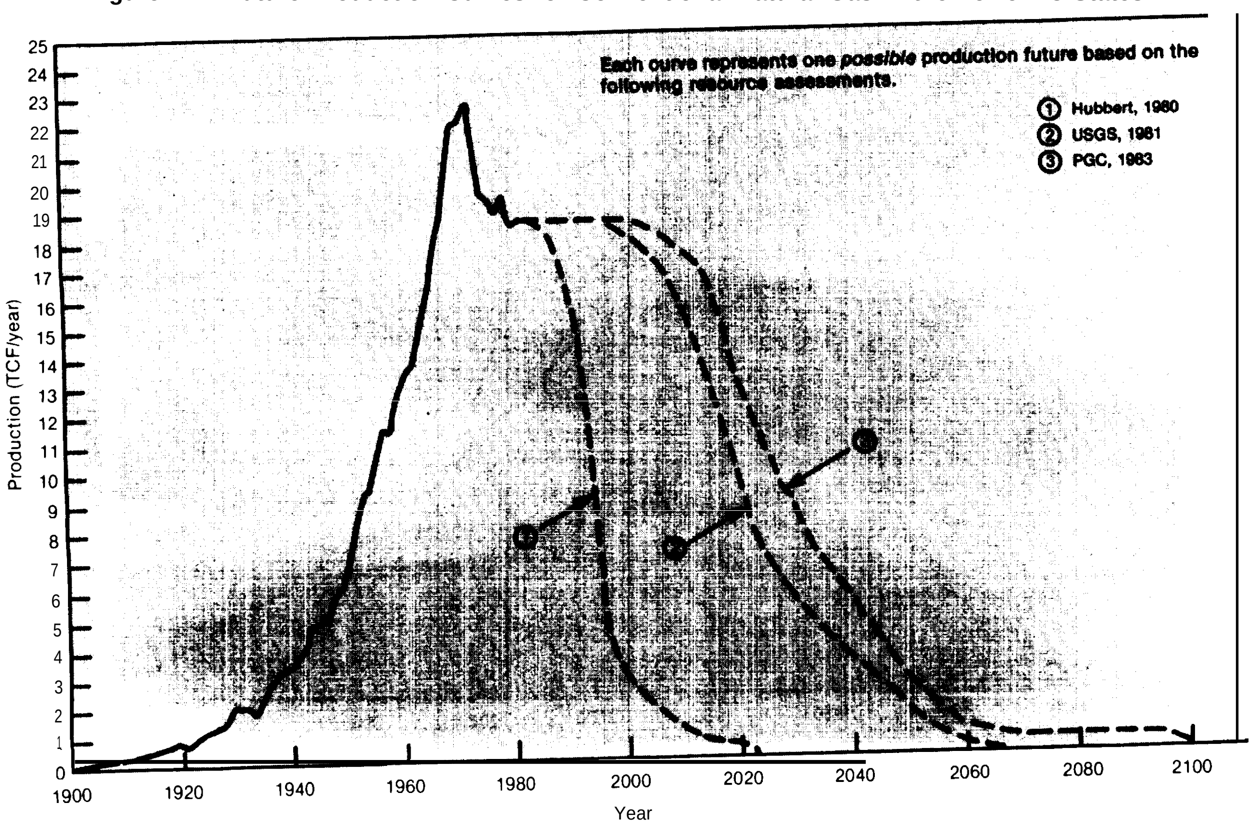
Projecting future gas production by graphing the complete production cycle is based on the expectation of M. King Hubbert that the complete cycle of production will somewhat resemble a bell-shaped curve and that knowing the area under the curve—the total recoverable resource —allows a reasonable facsimile of the entire curve to be drawn, once about a third or more of the production cycle has been completed. Hubbert used this approach in 1956[17] to show that then-current estimates of the remaining oil resource base implied that oil production was on the verge of peaking and then declining.

In this application, gas production values for 1900-82 were plotted, and three freeform curves were extended from the 1982 production rate such that the area under the curves equal led the remaining gas resources estimated by, respectively, Hubbert, USGS, and PGC (see table 6). These curves are shown in figure 24.

The curves show that Hubbert's assessment implies an extraordinarily sharp decline in production, so that by 2000 the total Lower 48 production rate would be about 3 TCF. Since there is little flexibility in drawing this curve, it appears

[17] M. K. Hubbert, "Nuclear Energy and Fossil Fuels," in American Petroleum Institute, *Drilling and Production Practice (1956)*, cited in M. K. Hubbert, "Techniques of Prediction as Applied to the Production of Oil and Gas," *Oil and Gas Supply Modeling*, S. I. Gass (cd.), National Bureau of Standards Special Report 631, May 1982.

**Figure 24.—Future Production Curves for Conventional Natural Gas in the Lower 48 States**



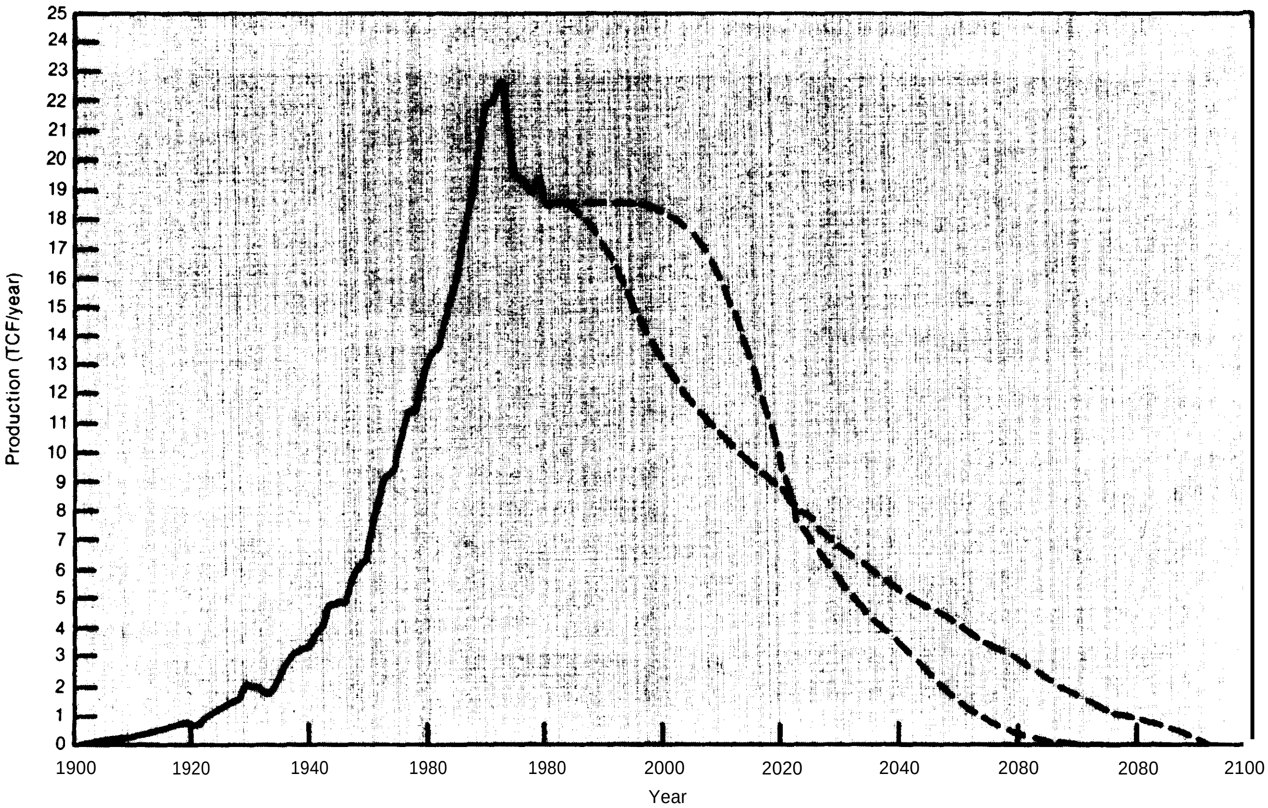

SOURCE: Office of Technology Assessment.

unlikely that the range of uncertainty due to the selection of the curve's shape is greater than about **2 to 5 TCF in 2000.**

The curves representing the USGS and PGC gas resource assessments were drawn so that the declining portion of the curve resembles a mirror image of the ascending portion. Both curves show production rates staying steady at least until 2000. A plausible physical interpretation of the curves is that they represent a resource base that still retains a substantial number of large fields amenable to rapid rates of production. Furthermore, the shape of the curves is clearly aligned with high demand for gas and prices that encourage substantial development drilling as well as vigorous exploratory efforts.

The USGS and PGC curves obviously can be redrawn to reflect different conceptions of how the production cycle might unfold. However, the necessity of maintaining existing production trends in the early years and of tapering off gradually as the resource is depleted limits the options. Figure 25 shows the original USGS curve and a second curve that reflects a different conception, that of a production decline that commences earlier but proceeds at a more gradual rate. This second curve might reflect a future where industrial demand for gas declines and exploratory activity and development drilling proceed at a lower level. It might also reflect a resource base whose fields are smaller, in more difficult to develop locations, and of lower average permeability.

**Figure 25.—Two Production Futures, One Resource Base: Alternative Representations of Future Production of Conventional Natural Gas in the Lower 48 States, Based on the USGS (1981) Resource Assessment (mean estimate)**




SOURCE: Office of Technology Assessment.

# A RANGE FOR FUTURE GAS PRODUCTION

In comparing figures 24 and 25 to the production projections produced by the alternative methods, some interesting conclusions can be drawn. First, the higher **end of the production ranges, which shows essentially stable production levels out to** 2000, appears to be quite compatible with the USGS and PGC **curves,** as drawn in figure 24. It should be remembered, however, that there are interpretations of the detailed physical nature of the gas resource base that, while compatible with the **overall magnitude** and even the regional estimates of USGS or PGC, could be completely **incompatible** with the high year **2000 production projection.** The second curve in figure 25 displays such an alternative interpretation, and there are more radical possibilities as well. *

A second conclusion is that the lower end of the production range—about 9 TCF by 2000—is really much too optimistic for a believer of the Hubbert or RAND resource estimate. This is because the assumptions of the lower end of the range, while appearing to be pessimistic to a "resource optimist, " may actually appear somewhat optimistic to a "resource pessimist. " This end of the range assumes that the fairly low new field discovery rates of the early 1970s are more realistic as a long-term average than are the higher rates of the last few years, but it ignores the possibility that even these low rates might go **down still farther as resource depletion continues.** Consequently, the true production implication of the range of resource base estimates cited in table 6 is likely to be a year 2000 range of about 4 to **19 TCF rather than the range of 9 to 19** TCF expressed by the first three projection approaches. *

As discussed in chapter **4,** OTA believes that the Hubbert and RAND estimates are overly pessimistic and that a more likely lower bound for the remaining recoverable gas resources is about 430 TCF rather than Hubbert's 244 TCF or RAND's 283 TCF. This higher value is compatible with a 2000 production rate of 9 TCF. Consequently, in our opinion, a reasonable range for **Lower 48 conventional natural gas production for the year 2000 is 9 to 19 TCF.** Similarly, **a reasonable range for** *1990* is **14 to** 20 **TCF.**

Finally, figure 24 illustrates an important point about the current "optimistic" assessments of the recoverable resource base: that these, too, imply an inevitable decline in conventional gas production, although the date of decline is perhaps 20 or 30 years later than that dictated by a pessimistic (430 TCF) resource base assessment. It must be stressed, however, that the additional 20 years or so of leeway implied by the more optimistic assessments seem likely to yield sufficient changes in prices and technology to allow the entry of nonconventional gas sources to the market and the movement of large amounts of conventional resources from "subeconomic" to ''economic. These potential sources of gas production are outside the boundaries of the resource base assessments and production forecasts discussed in Part I of this report, but they will be extremely important to future U.S. gas production.

*One such possibility would be a resource base that, while large, had most of its resources in hard-to-find, slow-to-produce fields. The future production "cycle" would then show a significant production drop in the next 20 to 30 years, followed by a very long period of low but stable production.

"It is important to remember that the kind of radical drop in production dictated by the most pessimistic of the resource base estimates will likely violate their baseline assumptions of maintenance of existing cost/price relationships—except for Hubbert's assessment (Hubbert believes his methodology "captures" future changes in price/cost relationships and technology). Although many present gas customers can switch without extreme difficulty to oil products or to electricity (assuming supplies of these are available), a rapid drop in production would still tend to push gas prices sharply upwards. This in turn would tend to Increase the resource base by moving subeconomic resources into the economic, recoverable category.

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# PUBLIC AND PRIVATE SECTOR FORECASTS OF FUTURE GAS PRODUCTION

Comparisons of alternative gas production forecasts have many of the same problems as comparisons of gas resource base estimates (see ch. 3, table 4). The economic, regulatory, and other "scenario" conditions assumed for the forecasts are not always made clear. Because the range of reasonable future values/assumptions for these conditions are so broad, it is probably safe to assume that there **are** major scenario differences between different forecasts. The resources measured may differ, with some forecasts including only "conventional" gas and others including all methane sources, especially gas from tight sands. The extent to which some of the commonly used resource base estimates (which are important variables in some of the forecasts, directly determining finding rates or defining an upper limit for cumulative discoveries) contain unconventional resources is not always clear, For example, the PGC acknowledges that as much as 20 percent of its estimated "potential resource" is in tight sands,[18] but other estimates do not specify such a percentage. Consequently, even the forecasters, themselves, do not always know how much tight gas is incorporated in their production forecasts. *

Table 28 presents the results of 21 public and private sector production forecasts of conventional Lower 48 gas production.** All are a few years old. Four of the forecasts explicitly include tight sands and/or Devonian shale; these are noted on the table.

The extent of agreement about future gas production displayed in table 28 is in sharp contrast to the very wide range projected by OTA. For the year 2000, a range of 11 to 15 TCF/yr–an extremely narrow range, given different base assumptions, forecasting methods, etc.—would encompass 13 of the 15 estimates available for that date. In contrast, OTA believes that an appropriate range for year 2000 production is 9 to 19 TCF/yr. Part of this difference may be attributed to the fact that most of the values in the table represent forecasts of "most likely" gas production rates, and there may be a tendency for such estimates to cluster together. In conjunction with this possibility, a lack of documentation for many of the forecasts makes it unclear whether they are all independent, original estimates. Some may simply be averages of other forecasts, reflecting the "conventional wisdom. "

Of particular interest is a comparison of AGA's year 2000 estimate–1 2 to 14 TCF/yr–and the production implications of the AGA-supported PGC's gas resource assessment. PGC'S assessment seems most compatible with production levels of 15 or 16 TCF/yr, or higher. If the AGA production forecast is intended to be associated with the PGC resource base, then AGA is using a most pessimistic interpretation of the resource base, at least from the standpoint of maintaining production rates at high levels during the next few decades.

A striking feature of the table is that all but one of the forecasts project substantial declines in gas production, most within 10 years and all but the one "dissenter" by 1995. It is important to recognize that these forecasters include some prominent gas "optimists." Much of the current optimism about gas's future must stem from confidence in supplementary supplies from unconventional sources, from Alaska, from Mexico and Canada, and from LNG imports. (Chapter 6 provides a brief discussion of the potential from all of these sources except unconventional production, which is the subject of Part II of this report.) However, it also seems likely that a resurvey of these forecasts, using the latest 1984-85 results, would show a higher range for the year 2000 production than in the original 1982 and earlier forecasts.

spotential Gas Agency, news release, Feb. 26, 1983.

*Further, there may not be agreement as to what constitutes "tight gas. " For example, the Federal Energy Regulatory Commission includes a maximum permeability of 0.1 millidarcies in its definition, while the National Petroleum Council used 1 millidarcy as the limit in its report on unconventional gas sources.

* "Including associated/dissolved gas (gas colocated with oil), on a dry basis.

**Table 28.–A Comparison of Conventional Lower 48 Natural Gas Supply Forecasts (TCF)**

| Company | 1985 | 1990 | 1995 | 2000 |
|---|---|---|---|---|
| 1. Gulf | 19.4 | 18.8 | 16.7 | 13.8 |
| 2. Texaco | 18.9 | 16.1 | 14.0 | 13.0 |
| 3. Chevron | 18.2 | 18.0 | 16,5 | 14.0 |
| 4. Exxon | — | 14.6 | — | 14.1 |
| 5. Sheila | 17.0 | 13.9 | 11.5 | 8.9 |
| 6. Conoco[b] | 19.0 | 18.0 | — | 14.6 |
| 7. Union | 19.2 | 18.0 | — | — |
| 9. Standard Oil (Indiana)[c] | 18.5 | 17.7 | 16.5 | 15.5 |
| 10. Tenneco | 18.0 | 15.4 | 13.5 | 11,9 |
| 11. AIR | 15.5 | 13.6 | — | — |
| 12. AGE | 16.0-18.0 | 5.0-17.0 | 3.5-15.5 | 12.0-14.0 |
| 13. GRI | 17.9 | 15,1 | 12.8 | 11,6 |
| 14. DOCK | — | — | — | 12.8 |
| 15. GAO | 16.5 | 14.8 | 14.0 | 13,5 |
| 16. E. Erikson | 17.4-18.5 | — | — | — |
| 17. ERA | 17.3 | 14.9 | 14.0 | |
| 18. ICE | 16.1 | 14.3 | 12.4 | — |
| 19. IEA/OECD[b] | 16.5-18.0 | 14.0-17.0 | — | 11-15 |
| 20. Chase Bank[b] | 18.3 | 17.7 | — | — |
| Average | 18.1 | 16.6 | 15.3 | 14.3 |

aMarketed gas rather than actual total (dry) production Excludes increased production from fields that are "forever controlled" under NGPA and that Shell believes could be obtained with decontrol
bNumbers Include tight sands
cAverages include interpolated data.

REFERENCES
1 Gulf Oil Corp., US Energy Analysis Task Group, Pittsburg, PA, *U.S Environmental Assessment 1982 Scenarios,* June 1982 "Business as Usual" scenario (In. eludes Lower 48 and southern Alaska)
"2 Texaco Inc., Economics Division, Finance and Economics Department, White Plains, NY, *United States Energy Outlook 1980-2000* February 1981 (Forecast of Marketed Productlon)
"3. Standard Oil Co of California, Economics Department, San Francisco, CA Preliminary forecast from forthcoming publication
4 Exxon Co., USA, Houston, TX, *Energy Outlook 1980-2000,* December 1980
•5 Shell Oil Co., Exploration and Production Economics Department, Houston, *TX, National Energy Outlook to the Year 2000. July 1982* (Fall 1981 Analysts Dry Marketed Gas)
"6 Conoco.Inc., Coordinating and Planning Department, Stamford, CT, *World Energy Outlook Through* 20@, January 1982
"7 Union Oil Co, Oil and Gas Division, Planning and Valuation, Los Angeles, CA
"8 Marathon Oil Co., Economics Department, Findlay, OH
"9 Standard Oil Co (Indiana), Chicago, IL Amoco's forecast includes nonhydrocarbon gases and is specifically done on adry gas basis Its 1985 forecast number IS demand-constrained
•10 Tennessee Gas Transmission Co., Economic Analysis and Long Range Planning Department, Houston, TX, *Energy 7982.2000,* August 1982
"11 American Natural Resources Co., Detroit, Ml, *United States Energy Outlook 1980-2000.*
*12* American Gas Association, Gas Supply Committee, Arlington, VA, *The Gas Energy Supply Outlook 1980-2000,* January 1982
"13. Gas Research Institute, Washington, DC, *Gas Research Insights,* October 1982
14 US Department of Commerce, Washington, DC, *US Energy for the Rest of the Century,* July 1982
15 General Accounting Office, Washington, *DC, Analysis occurrent Trends in US. Petroleum and Natural Gas Production,* Dec 7, 1979
16 Dr. Edward W Erickson for Natural Gas Supply Association, Natural Gas *Policy Act A Pragmatic Analysis,* January 1981
17 Energy Information Administration, U.S Department of Energy, Washington, DC, *1981 Annual Report to Congress,* February 1982
18 ICF Inc, Washington, DC, "The Economics of Gas Supply" as published in *The Energy Journal, vol. 3, No 4,* October 1982
19 International Energy Agency, OECD, *World Energy Outlook,* Paris, 1982
20 Chase Manhattan Bank, Energy Economics Division, New York Best estimate forecast from forthcoming publication

SOURCE Jensen Associates, Inc , "Understanding Natural Gas Supply in the United States," contractor report to the Office of Technology Assessment, April 1983

Chapter 6

# Gas Imports—An Overview

# Contents

## Chapter 6

# Gas Imports—An Overview

Natural gas imports in 1983 totaled 918 billion cubic feet (BCF)[1] and composed 5.5 percent of the total U.S. dry gas consumption. The current import status and future import projections are summarized in table 29.

In evaluating potential import supplies of natural gas to the Lower 48 States, the most obvious sources are the border countries, Canada and Mexico. Canada has been and probably will remain our most important source of supplemental natural gas. In January 1983, the National Energy Board recommended an additional 9.25 trillion cubic feet (TCF) of reserves for export. Although this decision nearly doubles the exportable quantity available to the United States, actual imports will depend on U.S. demand and competitive pricing. An important uncertainty in this regard is the effect of recent Canadian initiatives to price their gas more competitively in the current U.S. market. In the long run, the increase in allowable exports will probably help encourage frontier development.

[1] U.S. Department of Energy, Energy Information Administration, "U.S. Imports and Exports of Natural Gas, 1981," June 1982.

Exports from Mexico will probably remain at or below 300 million cubic feet per day (MMCF/day) in the near term, consistent with what they have been since the present contract was *nego*tiated in 1979. In fact, Mexico temporarily ceased gas exports to the United States in the fall of 1984 because of the pressure for *lower* gas prices in the current weak U.S. market. Although Mexican natural gas supplies are bountiful, the Mexican Government's current export philosophy seems to preclude significant increases in exports to the United States. Mexican consumption is expected to increase as the distribution infrastructure develops.

Alaska represents another large potential supply; the Prudhoe Bay Field alone constitutes over 10 percent of the total U.S. proved reserves. At

**Table 29.—Natural Gas Imports Summary Table**

| Source | Natural gas supplied to Lower 48 States in 1983 | Allowable imports under recent licenses/contracts | Proved reserve estimates (Dec. 31, 1982) | Range of future export estimates 1990 | 2000 |
|---|---|---|---|---|---|
| Mexico | 0.07 TCF (AGA/GER) | 0.11 TCF (AGA/GER) | 76 TCF (OGJ) | 0.1-1.0 TCF (AGA, LA-Mexico) | 0-1.5 TCF |
| Canada | 0.7 TCF (AGA/GER) | 1.75 TCF (AGA/GER) | 97 TCF (OGJ) | 1.0-2,5 TCF (AGA, LA-Canada) | 1.0-3.0 TCF |
| Alaska | 0 | — | 35 TCF (EIA) | ANGTS[b] 0.7-1.2 TCF; Pacific-Alaskan LNG 0.1-0.2 TCF (AGA) | |
| LNG | 0.13 TCF (AGA/GER) | 0.9 TCF[c] | 235 TCF (OGJ)[d] | Variable—depends on future U.S. policy and pricing. | |
| Total | 0.9 TCF (EIA) | | | | |

aThis range represents the highest and lowest estimates of the references cited.
bAlaskan Natural Gas Transportation System.
cThis value represents the total contract volumes for completed terminals.
dReserve of SIX countries (other than U S.) *currently* exporting LNG

REFERENCES

AGA—American Gas Association, The *Gas Energy Supply Outlook:* 198.3-2000, October 1983.
AGA/GER—American Gas Association, Gas *Energy Review,* various dates
EIA– Energy Information Administration, *U.S. Crude Oil, Natural* Gas, *and Natural Gas Liquids, 1982* Annual Report
LA–Canada– Lewin & Associates–Canadian *Natural Gas: A Future North American Energy Source?* January 1980
LA– Mexico– Lewin & Associates–Future *Mexican Oil and Gas Production,* July 1979.
OGJ —*Oil and Gas Journal,* December 1982 and other issues.

SOURCE' Office of Technology Assessment.

present, there is no natural gas production reaching the Lower 48 States, owing to the lack of a means of transportation. Financing for a transportation project is difficult to obtain because of current surplus supply and market prices below levels necessary for financial success. Despite a waiver package to eliminate roadblocks to private financing, the Alaska Natural Gas Transportation System project still has not achieved adequate financing arrangements. A rival TransAlaska Gas System would enable North Slope gas to be marketed outside of the domestic market. A methanol conversion alternative would allow the gas to be marketed either domestically or internationally. Neither of these alternatives appear to have good prospects for the immediate future,

Throughout the early to mid-1970s, liquefied natural gas (LNG) contracts were viewed as a favorable means of achieving long-term natural gas supplies. Since that time, the supply scenario has changed significantly, and LNG purchasers are now confronted with high-priced gas during a time of gas surplus. In the near term, there is little incentive to increase LNG imports; however, the availability of the long-term contracts and the opportunity to diversify U.S. supply may prove to be attractive in the future.

## MEXICO

Mexico had reported 75.4 TCF of proved reserves as of December 1981. Within the last 4 years, large reserve additions have caused Mexico's reserve-to-production ratio to double from 30 to 60.

Most of Mexico's gas production is from wells associated with oil; nonassociated wells are typically not put into production. This practice reflects Mexico's policy of exporting oil and using natural gas primarily to meet domestic energy demands. Mexico exports only the surplus gas remaining after domestic demand is met, which could in the future become a limiting factor to export levels. Mexico's current export maximum of 110 BCF/yr was established in 1979 by a contract with Border Gas, a U.S. pipeline company.[2] This quantity is recognized as a compromise between Mexican policy makers, who believe energy exports are necessary to bolster Mexico's ailing economy, and those who believe the resource should be saved for future domestic use. Because of the low gas demand and low market price in the United States, actual import levels had been reduced to the 60 percent minimum take-or-pay level, causing 1983 imports to be about 72 BCF.[3] Mexican exports to the United States have now been temporarily suspended because of the unfavorable market conditions.

Mexico has been successful in encouraging conversions to natural gas, and, as a result, domestic gas demand has been growing at a rate of 13 percent per year.[4] Because Mexico's financial condition has precluded investment in distribution equipment, the primary constraint to increased domestic consumption is a lack of transmission and distribution capability. As the distribution system develops and the process of converting end users to gas progresses, domestic consumption will increase, which could further constrain the exportable surplus.

Early in 1982, the Mexicans talked of increasing exports to 500 MMCF/day and later to 1,000 MMCF/day; however, these plans were not carried out, owing to problems with gas-gathering systems and budget cutbacks.[5] The factors that will determine the actual value of future imports include the progress of Mexico's economic growth and attempted reliance on gas for domestic

[2] Border Gas is owned and controlled by six interstate pipeline companies: Tennessee Gas Transmission Co., Texas Eastern Transmission Corp., El Paso Natural Gas Co., Transcontinental Gas Pipeline Corp., Southern Natural Gas Co., and Florida Gas Transmission Co.

[3] J. L. Wingenroth and A. A. Bohn, "Mexican Gas Supplies to the United States," *Gas Energy Review,* American Gas Association, August, 1984.

[4] *Petroleum Intelligence Week/y, Special Supplement,* "Mexico's Expanding Role in World Oil Markets," June 28, 1982.

[5] Ibid.

needs, the levels of demand for Mexican oil,[6] any changes in Mexico's view of gas as a natural patrimary, and future U.S./Mexican export/import agreements. Also, development of its substantial resources of non associated gas could greatly affect future exports.

There is a considerable range of estimates for the future quantity of Mexican gas available for export to the United States. In their "high success" case, Lewin & Associates estimate that annual exports will rise to 766 BCF in 1990 and then decrease to 255 BCF by 1995 and O by 2000.[7] The American Gas Association (AGA) is considerably more optimistic in its long-run projections and estimates that between 100 and 1,000 BCF/yr will be available in the 1990s and between 100 and 1,500 BCF/yr will be available by 2000.[8] The upper end of the range reflects a potential Mexican response to inadequate oil revenues using increased gas exports to stabilize its national income.

[6] Oi I demand is a factor not on ly because oi I production drives associated gas prod uction, but also because 01 I revenues are necessary for the Mexican economy, andlow 01 I exports wou ld exert pressure on Mexico to increase gas exports.

[7] Lewin & Associates, *Future Mexican Oil and Gas Productlon,* July 1979.

[8] American Gas Association, *The Gas Energy Supply Outlook: 1983-2000,* October 1983,

# CANADA

Canada also has large natural gas reserves, estimated at **97** TCF.[9] Its ultimately recoverable resource base estimate of **420** TCF[10] could be increased considerably by developing unconventional gas in Western Canada. At present, the technology to produce most of these low permeability reservoirs has not been demonstrated.

Marketability problems have created a large surplus export capability, and, until recently, Canadian exporters had succeeded in marketing only about 40 percent of their allotment of exportable gas. **In January 1983, in an attempt to alleviate the situation, the National Energy Board nearly doubled the exportable quantity of gas available to the United States. Also, in April 1983, the price was reduced from $4.94 per thousand cubic feet** (MCF) to **$4.40** per MCF to compete more readily in the U.S. market. In July 1983, an incentive sales program was added that made additional gas available at $3.40 per MCF to purchasers buying specified quantities of regularly-priced Canadian gas. In July 1984, the Canadian Government announced a policy, effective November **7, 1984,** that gave gas exporters the option of negotiating prices with their customers, with a price floor at the wholesale price of natural gas at the Toronto City gate.[11] Despite these efforts, decreased U.S. demand and improved short-term domestic supply prospects may still keep U.S. imports of Canadian gas low in the near term. There is, however, considerable disagreement about the effect of the new Canadian pricing policies, and some Canadian producers have been newly successful in selling to the U.S. market. The price considered acceptable by the Canadians will be a dominant factor affecting the level of exports to the United States. In the longer term, if the U.S. surplus disappears, Canadian exporters should be well-positioned to substantially expand their gas sales to the United States.

The 1980 National Energy Plan (NEP) has had important effects on the Canadian petroleum industry. The NEP established guidelines aimed at enabling Canada to achieve energy self-sufficiency by 1990. Several NEP objectives include:

- encourage substitution of gas for oil by favorable pricing;
- increase Canadian ownership of the domestic petroleum industry to **50** percent by 1990;

[9] Robert ]. Enright, "World 011 Flow, Refining Capacity Down Sharply; Reserves I ncrease,' *Oil and Gas Journal,* December 1982.

[10] R M. Procter, p, J. Lee, and D, N. Skibo, "cd nada's Conventional 011 and Gas Resources,'" Geological Survey of Canada, Open File 767, March 1981, p. 27.

[11] *Oil and Gas Journal,* "Canada Allows Gas Exporters to Negotiate Prices," July 23, 1984.

- stimulate frontier exploration off the East Coast and in the Arctic;
- allow a 25 percent back-in interest for the Canadian Government on federal leases; and
- increase the Canadian Government's share of petroleum revenues relative to those received by industry and the producing provinces.

The increased regulation of the NEP has had a noticeable negative impact on risk investment. Canadian operators and support companies have left Canada for more lucrative prospects in the United States. Many petroleum companies have cut expenditures and long-term projects and suffered severe losses. These effects, if not reversed, could lessen the quantity of gas produced in the remainder of the century, thereby limiting the availability of surplus for export to the United States.

Another factor affecting gas export is the level of Canadian gas consumption. In an attempt to reduce the need for expensive foreign oil imports, the Canadian Government is encouraging increased use of natural gas and has provided several incentives for doing so, such as favorable gas prices, grants, and loans. The NEB forecasts natural gas demand to increase at 4 percent per year during the 1980s and 3 percent per year throughout the 1990s.[12] Although the conversion process is progressing slowly, the quantity of gas available to the United States could be" constrained if Canadian consumption increases substantially in the future.

Under current Canadian export agreements, natural gas exports will increase to about 1.6 TCF/yr by 1990 and then decline to about 0.15 TCF/yr by 2000.[13] AGA **estimates that between 0.8 and 1.8 TCF/yr** will be exported by 1990 and 1.0 to 2.4 TCF/yr by 2000.[14] Lewin & Associates believe that technological advances in the frontier areas and the development of unconventional gas could allow exports of **2.5** and **3.0** TCF/yr in 1990 **and 2000, respectively.**[15]

[12] National Energy Board, "Omnibus '82 Backgrounder," Jan. 27, 1983.
[13] Ibid.
[14] American Gas Association, *The Gas Energy Supply Outlook: 1983 -2000,* October 1983,
[15] Lewin & Associates, *Canadian Natural Gas: A Future North American Energy Source,* January 1980,

# ALASKA

The massive hydrocarbon potential of Alaska was realized with the discovery of the Prudhoe Bay Field in 1968, which added 26 TCF to estimated U.S. proved gas reserves. Reserve estimates for Alaska average 35 TCF, and resource base estimates are as high as 169 TCF.[16]

Despite the substantial quantity of reserves in Alaska, lack of a transportation system has precluded marketing of Alaskan gas to the Lower **48 States.** The Alaskan Natural Gas Transportation Act of 1976 directs the President, subject to congressional approval, to establish a means to transport Alaskan natural gas to the Lower 48 States. To ensure domestic use of the resources, the Export Administration Act of 1979 forbids the export of North Slope hydrocarbons to non-U.S. customers. Several transportation methods have been proposed; not all of these have designated the Lower 48 States as the final market.

In September 1977, the Alaskan Natural Gas Transportation System (ANGTS) was chosen over several alternatives. The 4,800-mile pipeline was to be routed from Prudhoe Bay across Alaska and Canada to Alberta, and split into a western leg to California and an eastern leg to Illinois. Despite a waiver submitted by President Reagan and approved by Congress in mid-December 1981, to remove any legislative deterrents to private financing, the pipeline has not yet been financed. Investment capital has been difficult to attract because the marketability of the gas is questionable. ANGTS is estimated to cost between $38.7 billion and $47.6 billion[17] and deliver gas at prices

[16] Potential Gas Committee, *Potential Supply of Natural Gas in the U. S.,* June 1983.

[17] American Gas Association, *Gas Energy Review,* vol.10, *No.* 1, January 1982.

estimated between **$4.85 per** MCF[18] and $20 per MCF.[19] ANGTS is the only pipeline transportation scheme designed to market North Slope natural gas in the Lower 48 States. AGA currently does not project any pipeline imports from Alaska by 1990 but expects imports of 0.7 to 1.2 TCF by 2000, assuming that the pipeline is built.[20]

Converting North Slope gas to methanol could provide an alternative market for the gas. The principal advantage of the methanol option is that the existing oil pipeline system could be used to transport the methanol from the North Slope to Valdez, assuming capacity were available. The major problems with the methanol alternative are the high energy loss associated with conversion and the potential that future demand for methanol might be insufficient to absorb Alaskan production. Also, costs would be very high; estimated first year costs for conversion and transportation range between $14.24 and $17,24 per million Btu (MM Btu).[21]

Two LNG projects have been proposed to market Alaskan gas. The Alaska Governor's Economic Committee recommended the TransAlaska Gas System (TAGS). The TAGS requires an 820-mile pipeline from the North Slope to the Kenai Peninsula, where the gas would be liquefied and shipped to foreign markets, principally Japan. If this proposal is adopted and an executive order or legislation declaring gas exports to be in the national interest is obtained, the Lower 48 States may never receive supplemental gas from the North Slope. Another LNG proposal, the Pacific Alaska LNG Project, calls for the shipment of south Alaskan LNG to receiving facilities on the California coast; however, the potential supply contribution from this project is small. AGA estimates between 0.1 and 0.2 TCF could be supplied by 2000, depending on the construction schedule.[22]

[18] *International Gas Technology Highlights,* "Alaskan Pipeline Costs Could Be Lower Because of Delay Northwest Heat," Aug. 30, 1982.

[19] *Oil and Gas Journal,* "Angt~ Seen Top Option for Alaskan Gas," Aug. 9, 1982, p. 61

[20] American Gas Association, *The Gas Energy Supply Outlook 1983-2000,* October, 1983,

[21] Congressional Research Service, *Major Issues Associated With the Alaska Natural Gas Transportation Waivers* Dec. 18, 1981.

[22] American Gas Association, *The Gas Energy Supply Outlook 1983-2000,* October, 1983

# LIQUEFIED NATURAL GAS

During the early to mid-1970s, when the United States was confronted with natural gas shortages, LNG imports appeared to be a favorable supplemental supply alternative. Several long-term contracts were established with Algeria. Since then, the supply situation has changed drastically, and in the midst of a natural gas surplus, LNG purchasers are confronted with very high-cost gas supplies.

Although existing agreements enable imports of up to 800 BCF/yr, the United States imported only 132 BCF of LNG in 1983 at two of four existing receiving facilities. The Distrigas facility in Everett, MA, received 36,4 BCF and the Lake Charles, LA, facility received 119.9 BCF since its first shipment in September 1983. Small amounts of LNG were also trucked from Canada to New England. Also in 1982, the United States exported 60 BCF from Cook Inlet, AK, to Japan, and in 1981 was a net exporter of LNG.[23]

For purposes of evaluating future LNG availability, the LNG resource base includes any large reserves which, owing to remote location or lack of a transportation method, are not committed to existing markets. In 1978 OTA estimated that of the 2,257 TCF of proved reserves in the world, about 812 TCF were surplus (635 TCF of the surplus are located in the U. S. S. R., Iran, and Algeria[24]). Although reserves are plentiful, high costs preclude a large percentage of natural gas reserves from being made available as LNG. The total capital required for a world-scale LNG fa-

[23] U.S. Department of Energy, Energy Information Administration, "U. S." Imports and Exports of Natural Gas, 1981," June 1982.

[24] Office of Technology Assessment, *Alternative Energy Futures, Part. 1, The Future of L, WC,* March 1980,

cility (1 BCF/day) including production and liquefaction, transportation, and receiving and vaporization facilities is around $3 billion to $7 billion (1982$),[25] depending on shipping distance. Although the cost of service is dependent on interest rates and shipping distance, a cost of $3/MMBtu to cover liquefaction, transportation, and reconstitution of the gas would not be unusual.[26]

The future of LNG depends principally on pricing and policy. If the producing country demands a high price at the wellhead—as an extreme example, a price approaching parity with oil on a $/Btu basis–then the delivered price of the gas generally will be much higher than the price of competing fuels. Currently, the price of LNG is higher than market-clearing levels in the United States, and could be sold only by mixing the gas with lower cost gas and charging a price in line with the average cost. In fact, because the current cost of liquefaction, transportation, and reconstitution may be almost equal to the average wellhead price of new gas,[27] future imports of LNG will probably require both a substantial increase in U.S. domestic wellhead prices and a marketing policy on the part of the exporting nations that considers the transportation costs in pricing the gas at the well head.

[25] Napoli, R. N., "Economics of LNG Projects," *Oil and Gas Journal*, Feb. 20, 1984.

[26] Because many of the capital costs are sunk, however, this cost will not necessarily be added to the price of the gas.

[27] According to the February 1984, *Natural Gas M* (Energy Information Administration, DOE/EIA-0130 (84/02)), the average price for New Gas (NGPA secs. 102, 103, 108, and 109) was $3.59 per MCF.

# Part II

# Unconventional Gas Supplies

# Chapter 7

# Introduction and Summary: Availability of Unconventional Gas Supplies

# Contents

# Chapter 7
# Introduction and Summary: Availability of Unconventional Gas Supplies

## INTRODUCTION

The unconventional natural gas resources include low-permeability sandstone and limestone formations (commonly known as tight sands or tight gas formations), Devonian shales, methane-rich coal seams, and geopressurized aquifers. Methane hydrates—gas trapped with water in an ice-like state—and abiogenic, or "deep earth" gas–gas supposedly originating from the venting of methane from the Earth's core—have recently been added to the unconventional roster. Due to a combination of technical difficulties and high costs of production, gas found in these geologic circumstances has not, for the most part, been included in natural gas resource base estimates. However, higher gas prices and advances in technology developments have recently made some of the unconventional resources more attractive.

During the past 10 years, several Government and private organizations initiated studies to determine the size of these additional resources and the conditions necessary to develop them. The first comprehensive study of the unconventional resources was completed by the Federal Power Commission in 1973 as part of the National Gas Survey.[1] It was followed by studies by the National Academy of Science,[2] the Federal Energy Regulatory Commission,[3] Lewin & Associates under contract to the Department of Energy,[4] and the National Petroleum Council.[5] Results of these studies, and of other studies of individual resources, will be discussed in more detail in subsequent chapters.

A general consensus emerges from these studies that the total size of the unconventional natural gas resource base is extremely large, that with higher prices and more sophisticated technologies, significant quantities of gas could be recovered. Findings of the early studies undoubtedly provided the impetus to include gas from tight formations, Devonian shales, coal seams, and geopressurized brines in the high cost category (sec. 107) of the 1978 Natural Gas Policy Act (NGPA). The higher allowable prices for this category were intended to promote near-term development of these resources.

OTA's assessment deals only with the gas resource potential of the tight formations, Devonian shales, and coal seams. These resources are the best understood of the unconventional resources and appear to have the most potential for contributing to supply within the next 20 years. Gas from tight formations and, to a lesser extent, from Devonian shales currently is being produced in quantities sufficient to cause substantive problems with the definition of "unconventional," as discussed below. Gas from coal seams is also being produced, but in much smaller quantities. In contrast, our present level of understanding of the geopressurized aquifers suggests that they are less likely to be commercially viable gas producers within this century, although some researchers vigorously disagree with this view. Too little is known about the methane hydrates and their production requirements to allow an adequate assessment of their supply potential. Finally, the potential of "deep earth gas" is only conjecture at this time because there is no generally accepted proof of its existence in commercial concentrations.

[1] U.S. Federal Power Commission, Task Force Report of the Supply-Technical Advisory Task Force–Natural Gas Technology, in *National Gas Survey*, vol. 2, 1973.

[2] National Academy of Sciences, *Natural Gas From Unconventional Geologic Sources, 1976*, Energy Research and Development Administration Report FE-2271-1.

[3] Federal Energy Regulatory Commission, U.S. Department of Energy, *National Gas Survey: Nonconventional Natural Gas Resources*, DOE/FERC-0010, June 1978,

[4] W. A. Kuuskraa, et al. (Lewin & Associates, Inc.), *Enhanced Recovery of Unconventional Gas, Executive Summary, Vol. 1*, October 1978, and 2 other vols., U.S. Department of Energy Publication HCP/T2705-01, 02, 03.

[5] National Petroleum Council, *Unconventional Gas Sources*, 5 vols., 1980.



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## The Definition Problem

"Unconventional" is not, perhaps, the best term to characterize the gas resources under discussion, although we will continue to use it in this report for the sake of simplicity and adherence to customary usage. Tight gas and gas from Devonian shales, in particular, are not newly recognized resources. Certain fields that fit in these two categories have been producing gas for many years. These and other currently economic tight gas and Devonian shale formations are partly included in the conventional resource base estimates of the Potential Gas Committee, and a small amount may be included in the estimates of the U.S. Geological Survey and others. To evaluate its potential as an additional source of supply, the unconventional resource should include only those parts of the tight formations and Devonian shales which have not been considered economic to produce under existing economic conditions and technology. Coal seam methane resources can be more easily categorized since past production has been low. They are unlikely to have been included in past estimates of conventional resources.

As noted in Part 1, conventional resources generally are categorized by defining boundary conditions in terms of "existing economic conditions," "current technology," and other vague terms. Unfortunately, there currently are no widely accepted criteria defining these terms to allow a clear division between conventional and unconventional gas resources. Further, the boundary dividing conventional and unconventional resources is continuously changing through time due to changing economic conditions, increased geologic understanding, and greater technical sophistication. The poorly defined boundary causes considerable confusion in determining the size of the unconventional resource and the amount that it can potentially contribute to total U.S. natural gas supply.

The level of confusion is likely to continue. Most current estimates of the unconventional gas resource base and its supply potential have attempted to eliminate overlap with conventional gas resource estimates by excluding areas with existing production. But data sources for new production from unconventional formations do not clearly distinguish between existing and new producing areas. Since passage of the NGPA, most of the production data comes from Federal Energy Regulatory Commission (FERC) filings for section 107 (high cost gas) designation and from Purchase Gas Adjustment (PGA) filings that record gas purchases according to the NGPA categories. The FERC intended to exclude gas from existing producing formations when it determined criteria for designating formations eligible for section 107 classification. It was inevitable, however, that new wells drilled in a number of existing producing formations would satisfy the FERC criteria and be granted section 107 prices. As a consequence, it is no longer possible to distinguish between areas which previously were excluded from assessments of the unconventional resource and those which were included. Thus it is difficult to determine the extent to which resources classified as unconventional in past assessments are now being developed.

We will attempt to clarify and identify overlap between conventional and unconventional estimates of natural gas resource potential in the subsequent chapters. The reader should keep in mind that there are limited data available to make such distinctions and our conclusions are necessarily tentative.

## Relative Uncertainty

Estimates of gas-in-place, recoverable resources, and future production of **conventional** natural gas are characterized by a high level of uncertainty, as described in the previous chapters. Inevitably, similar estimates for the unconventional natural gas resources will be more uncertain still. Many of the same categories of uncertainty, such as lack of geological understanding, are magnified for the unconventional resources. Further, whereas estimates for the conventional resource focus on existing and relatively well understood technologies, most resource and production estimates for the unconventional resources attempt to foresee new technological developments, adding additional uncertainty. Finally, for the unconventional resources, there often is little of the production and discovery history that serves as a guide to projections for conventional gas, and what history does exist applies only to the small part of the overall resource that was accessible to past discovery and production technology.

The general level of uncertainty associated with estimates of the unconventional **resource base is somewhat different from that associated with projections of future unconventional production. Although resource and production estimates share some uncertainties about the geology of the resource, generally production estimates focus on the most accessible, and best understood portion of the resource—at** least for shorter term projections. On the other hand, projecting future production requires making assumptions about drilling rates and development schedules, about the pace of production research programs, about pipeline accessibility, and about the future progress of a number of institutional issues such as controversies about the ownership of coal seam gas, leasing difficulties in Devonian shale development, etc. In OTA's opinion, long-term projections of future unconventional gas production should be viewed as **at least** as uncertain as, and probably more uncertain than, estimates of gas-in-place and of recoverable resources at an assumed price and level of technological development.

Finally, it cannot be overstressed that any estimates of future production and recoverable resources that would purport to be "most probable" estimates are explicitly relying on an **assumption** both of the **level of effort** that Government and industry will put into the massive research and development necessary to gain access to the greater part of the unconventional resource, and of the **success** of that R&D program. past disappointments in technological forecasting should serve as a reminder that this type of estimate must always be viewed with a certain degree of healthy skepticism. In addition, these estimates are relying on assumptions of future gas prices and, in the case of production estimates, on assumptions of future gas demand. Both future prices and demand must be considered highly uncertain. For these reasons, virtually all recent estimates of recoverable resources and future production rely on a scenario approach wherein the effect of different price and technology assumptions are examined.

In the following summaries, the term **"gas-in-place"** denotes the total gas present in formations where some economic gas production is feasible; it therefore does not include every last molecule of gas present in the Earth. **"Technically recoverable resources"** denotes gas expected to be recoverable from these formations up to the limits of known technology, with little regard to price.[6] **"Remaining recoverable resources"** denotes gas that is expected to be recoverable under a set of price and technology assumptions defined by the estimator.

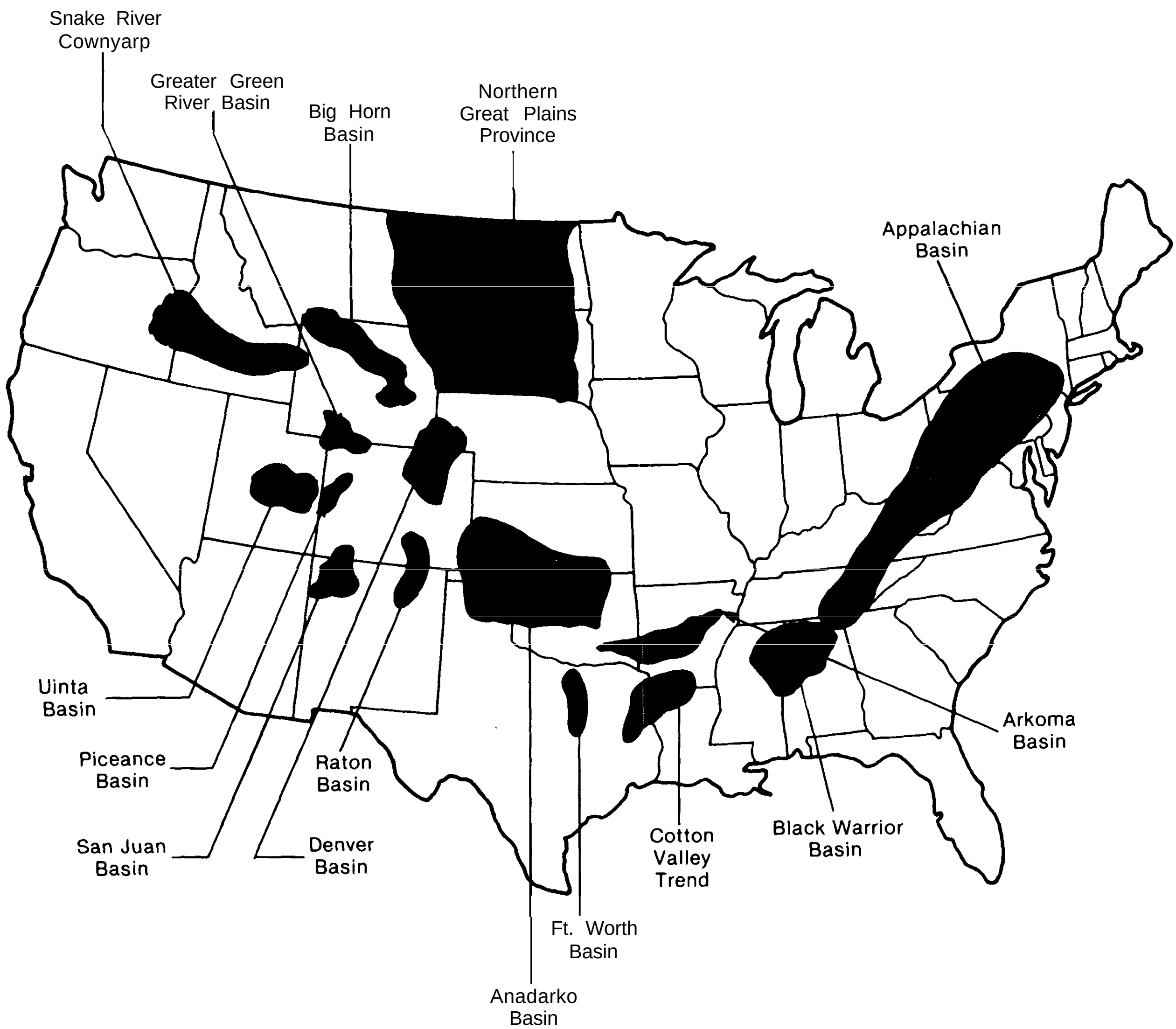
[6] This category is meant to include only those resources that can be extracted by technologies ordinarily used tor gas production For example, gas that theoretically could be obtained by mining and retorting shales would be excluded.

# TIGHT GAS

## Definition

Tight gas is natural gas that is found in formations of sandstone, siltstone, silty shale, and limestone that are characterized by their extremely low permeability–i.e., liquids and gases do not flow easily through them. Figure 26 shows the main tight gas-bearing basins in the Lower 48 States. Tight gas reservoirs represent the low-permeability end of a continuum of gas-producing reservoirs rather than a **unique** type. Over the past several decades, rising gas prices and improvements in production technology have encouraged gas producers to move to lower and lower permeability formations, and thus the boundary between "conventional" and "unconventional, tight gas" has continually shifted. In 1978, in order to allow price incentives to encourage production of high cost gas under the NGPA, FERC formally defined "tight gas" as hav-

**Figure 26.—Location of Principal Tight Formation Basins**




SOURCE: Morgantown Energy Technology Center, (modified by OTA) Department of Energy

ing a specified range of permeabilities and production rates.[7] The FERC definition is not universally accepted by resource appraisers, though, and all estimates of resources and future production from tight formations must be evaluated in the context of their defined boundary conditions. For example, the current estimate of potential gas resources published by the Potential Gas Committee—generally considered to be an estimate of **conventional** resources—contains over 150 TCF that PGC now categorizes as tight gas resources. OTA estimates that at least 30 TCF of the gas counted as unconventional tight gas by the National Petroleum Council in its 1980 report are included as well i n the PGC resource estimate.

[7]Under this definition, a tight gas reservoir is one having an average permeability of less than 0.1 md and a maximum production rate prior to stimulation, dependent on depth, of 44 MCF/d at 1,000 ft up to 2,557 MCF/d at 15,000 ft.

## Resource Characteristics

Although gas from tight formations generally is considered to be one resource, there are two distinct types of tight formations with significantly different producing characteristics. Blanket formations extend laterally over large areas, as befits their name. They occur either as one thin (10 to 100 ft thick) gas-filled layer or as many even thinner gas-filled layers alternating with clay-rich layers. Lenticular formations consist of many small discrete reservoirs, often shaped like lenses, separated by shales and sometimes by coal seams. They occur interspersed throughout formations hundreds of feet thick.

Three characteristics of the reservoir rocks in these formations are responsible for their low permeability. First, the grains that form the rock are small, which causes the individual pores in the rock and the connections between these pores to be small. This yields a very high ratio of pore surface area to pore volume, allowing high absorption of water which can physically obstruct gas flow; also, the small size of the pore connections inhibits flow. Second, the process of dissolution and precipitation of minerals in the rock, which has continued over geologic time, has blocked or impaired some of the pore space and connections between pores, further blocking gas flow. Third, the considerable amount of clay often present in the formations can swell in the presence of water and block flow paths, or can break apart and plug openings. The net permeability of the tight reservoirs also will be affected by any natural fracture systems in the rock, which provide alternative pathways for gas flow.

## Technology

Because of the poor flow characteristics of the reservoir rock in tight formations, economic levels of gas production generally can be achieved only by creating a manmade increase in permeability, by fracturing the reservoir rock surrounding the wellbore. This is most commonly achieved by hydraulic fracturing, which involves pumping a fluid u rider high pressure into the well until sufficient pressure is achieved to break down the rock. Because the fractures would tend to close when the fluid is removed–especially in deep reservoirs where the pressure of the rock is great—sand or other materials are added to the fluid. These "proppants" settle out of the fluids and are left behind in the fractures when the fluid is removed, serving as wedges to prevent the fractures from closing.

Successful fracturing in tight formations is complex and faces substantial obstacles. Although fracturing dates from the 1800s, and **hydraulic** fracturing dates from 1947 and has the benefit of the experience gained by thousands of separate fracturing treatments, the process is not fully understood and extrapolation to new geologic situations is difficult. Aside from the difficulty of **forecasting** what a fracture will do, it is hard to tell in any detail what a fracture **has done** even after it has been completed and the well is producing (or has proved to be unproductive). This is a primary reason why our extensive experience in fracturing has not been as much benefit in projecting future performance as might have been expected.

Despite the difficulties, fracturing has realized considerable success in tight formations, at least for the blanket formations. Achievement of long fractures has become fairly consistent, and fractures over 2,000 ft long have been reported. Substantial problems do remain, however. Operators must reduce the extent to which fractures grow vertically beyond the gas-bearing layers, lowering the overall efficiency of the treatment and losing reserves through water intrusion or degradation of the reservoir "cap." Problems associated with transporting proppants deep into the fracture, to prevent fracture closure, and with drilling fluid damage to formations from the swelling or dislodging of water-sensitive clays must be overcome. The degradation of permeability over time, associated with gradual fracture closure or with the blockage of pores and fractures by accumulated clay or sand, must be prevented. Also, the level of success achieved in the blanket formations has not been transferred to the lenticular formations, where large-scale fracturing treatments have apparently been **unsuccessful in con**necting remote gas pockets, called lenses, to the well bore—a necessary prelude to fully developing the lenticular resource. Developers of lenticular formations have tended to return to shorter, less expensive fracture treatments which may imply lower gas recovery.

## Resource Estimates

Gas-in-place estimates for tight gas have been made by the Federal Power Commission (1972), the Federal Energy Regulatory Commission (1978), Lewin & Associates for the Department of Energy (1978-79), and the National Petroleum Council (1980). These are shown in table 30. All but the NPC study limited their estimates to basins where detailed appraisals could be made, primarily basins in the West and Southwest. The NPC used a method of extrapolation to incorporate basins where less data were available, and thus it is the only estimate for the total U.S. resource.

In general, the later estimates build on the earlier ones, are more sophisticated, and have had access to better data. The Lewin and NPC estimates should be considered the most credible estimates to date of the in-place resource. However, there are substantial remaining uncertainties in even these estimates. Especially important are uncertainties in porosity and water saturation (which affect both the amount of gas present and its flow properties), in the areal extent and thickness of the gas-producing portions of the tight formations, and, in some basins, in the geologic history as it affected gas formation and preservation. These uncertainties are important in the appraised basins and are critical in the NPC's extrapolated basins.

- **porosity and water saturation** limit the amount of gas that may physically be present in the reservoir rock. These parameters are both extremely difficult to measure accurately and may vary over a wide range within a small area. This implies that the use of a limited number of data points to characterize a basin—a characteristic of all the estimates—leaves considerable room for error.
- **Areal extent and thickness** of the gas-bearing (pay) zones are direct determinants of gas volume. These are difficult to measure in several circumstances, for example, pay thickness for blanket formations containing multiple thin gas-bearing layers (stringers), or a real extent for lenticular sands when surface outcrops are not present.
- Geologic **history** affects the volume of gas present because' it determines the presence of source materials, temperature and pressure histories critical to the formation and preservation of gas, and the availability of a trapping mechanism. Substantial uncertainty occurs in any areas that have not been tested by drilling, and may also exist for certain potentially productive **layers** in explored territory. Areas affected by this uncertainty include the Northern Great Plains, the Piceance Basin, the northern part of the Denver Basin, and most of the extrapolated basins.

**Table 30.—Gas-in-Place Estimates for Tight Gas**

| Study | Gas-in-place, TCF |
|---|---|
| FPC , . . . . . . . . . . . . . . . . . . . . . . | 600 |
| FERC . . . . . . . . . . . . . . . . . . . . . | 793 |
| Lewin . . . . . . . . . . . . . . . . . . . . . | 423 |
| NPC (appraised basins) . . . . . . | 444 |
| NPC total . . . . . . . . . . . . . . . . . . | 924 |

SOURCE' Office of Technology Assessment.

Although arguments have been made favoring both higher and lower estimates of gas-in-place than those found in the NPC estimate, with an important exception, the arguments for neither view seem preponderant. The exception is the argument, based on geologic theory and on the current low level of development activity, that the NPC's estimate of 150 TCF for the Northern Great Plains' gas-in-place is considerably too high. In OTA's opinion, this is a distinct **possibility.** Otherwise, the NPC estimate of gas-in-place for the remaining 11 appraised basins–444 TCF minus 148 TCF for the NGP, or 296 TCF–should serve as a reasonable "most likely" estimate for those basins. A considerable error band-perhaps +/- 100 TCF–must be assigned to the latter value, however. The NPC's gas-in-place estimate for the entire United States—924 TCF—is considerably less reliable because of extreme uncertainty in the 480 TCF associated with the 101 basins whose resources were estimated by extrapolation rather than direct appraisal.

Estimates of the **recoverable** tight gas resources have been made by Lewin & Associates and the National Petroleum Council in conjunction with their gas-in-place resource estimates, and by the Gas Research Institute. These estimates are extremely sensitive to assumptions made about price, level of technology, and gas-in-place.

Lewin and NPC first estimated **technically** recoverable gas. Lewin computed a 50 percent recovery of the gas-in-place while NPC computed a 66 percent recovery; this reflects NPC's more optimistic technology assumptions, as discussed later. Thus, Lewin's estimate for recoverable gas from its appraised basins is 212 TCF, whereas NPC's is 292 TCF for a comparable set of appraised basins, NPC estimated a total U.S. recoverable resource of 607 TCF.

Estimates of **economically** recoverable gas resources vary over a wide range, from a conservative 30 TCF (base technology, $3/MCF in 1979$, Gas Research Institute) to 575 TCF (advanced technology, $9/MCF in 1979$, total United States, NPC), as shown in table 31.

At one extreme, GRI's relatively low estimates appear to reflect its desire to be conservative and to include only those tight resources that have a very high probability of occurrence and recoverability. At the other extreme, the NPC's considerably higher estimates reflect the extension of its analysis to the entire United States, its favorable assessment of gas resources in the Northern Great Plains, and its confidence in the effectiveness of tight gas production technologies. As noted in the discussion of gas-in-place, the extrapolated portion of the resource base and the Northern Great Plains resource appear to be highly uncertain. In addition, three key technology assumptions made by NPC appear to be quite optimistic, especially if taken together. These assumptions are:

1. **Fractures in lenticular sands will contact lenses distant from the wellbore.** Without such contact, gas recovery in the lenticular basins will be drastically reduced. At present, the ability to contact remote lenses has not been demonstrated.
2. **Present fracturing technology allows 1,000-ft fractures to be consistently achieved, and advanced technology will achieve 4,000-ft fractures.** The 1,000-ft fractures do not appear to be the current state of the art in shallow (e.g., Northern Great Plains) or lenticular formations, and 4,000-ft fractures appear optimistic for advanced technology in these same geologic situations.
3. **The longer fracture lengths can be achieved while reducing fracture heights, and thus reducing fracturing costs per foot.** This is opposite to current experience. On the other hand, there are approaches to achieving these conditions that do appear plausible.

In OTA's opinion, the optimism of this set of assumptions implies that the NPC estimates of recoverable resources should themselves be considered optimistic, that is, higher than a "most likely" estimate.

In OTA's view, all available estimates of recoverable tight gas are highly uncertain because of poorly defined reservoir characteristics and

**Table 31.–Economically Recoverable Gas at Two Technology Levels (TCF)**

| | Price per MCF | | Base technology | | Advanced technology | |
|---|---|---|---|---|---|---|
| | $ (study date) | $ (1983) | | | | |
| Lewin (1977) | 1.75 | 2.75 | 70 | | 149 | |
| | 3.00 | 4.70 | 100 | | 182 | |
| | 4.50 | 7.00 | 108 | | 188 | |
| GRI (1979) | 3.12 | 4.20 | 30 | | 100 | |
| | 4.50 | 6.00 | 45 | | 120 | |
| | 6.00 | 8.00 | 60 | | 150 | |
| | | | Total | Appraised | Total | Appraised |
| NPC (1979) | 2.50 | 3.35 | 192 | 97 | 331 | 142 |
| | 5.00 | 6.70 | 365 | 165 | 503 | 231 |
| | 5.00 | 6.70 | 365 | 165 | 503 | 231 |
| | 9.00 | 12.00 | 404 | 189 | 575 | 271 |

SOURCE Office of Technology Assessment

technologic uncertainties. However, despite our criticism of certain aspects of the NPC analysis, it seems basically sound to us, and we have little doubt that large quantities–at least a few hundred TCF–of tight gas will be recoverable provided gas prices reach at least moderately high levels in the future (e.g., $5 to $7/MCF in 1984$).

### Production Estimates

Estimates of future production of tight gas have been made by Lewin, NPC, and GRI, as well as by the American Gas Association (AGA).

GRI's production estimates for the year 2000 range from about 2 to 6 TCF/yr depending on price and technology. Because its estimates of recoverable resources are unexplained, the validity of this estimate is impossible to judge.

Both Lewin and NPC project high year 2000 production: 4.0 to 6.8 TCF/yr for Lewin (at $3/MCF, 1977$), 4.1 to 15.5 TCF/yr for NPC (at $5/McF, 1979$) depending on the phasing in of advanced technology and the drilling schedule. The NPC estimate is deliberately structured to represent a goal attainable by a concerted effort at developing the necessary technology and accelerating the pace of development.

AGA used the NPC analysis as a starting point and superimposed more conservative assumptions about drilling rates, implementation of new technologies, and initial production rates per well. The result is a projected year 2000 production rate of 4.3 TCF/yr, or 3 TCF/yr if definitional overlap between tight and conventional reservoirs is eliminated and a less optimistic outlook for the potential of the advanced technologies is assumed.

Several factors imply that the more conservative estimates should be considered more likely. The slow rate of technology development in the lenticular formations coupled with the importance of the lenticular Rocky Mountain Basins in the optimistic estimates is a critical factor. Similarly, the Northern Great Plains would normally be expected to play a major role in future development because much of the resource is projected to be recoverable at relatively low cost; however, here, too, there is controversy about the magnitude of gas available. The absence of pipelines in many potential tight gas production regions also implies a lower rate of development unless the market for new gas supplies improves dramatically in the near future.

Aside from being sensitive to geologic (accessibility of lenticular resource, magnitude of Northern Great Plains gas) and technologic assumptions, future production is also extremely sensitive to gas prices and to the availability of competing, and less costly, conventional gas prospects. OTA is extremely skeptical of the possibility of reliably forecasting either gas prices or conventional gas availability in the time frame in question. Consequently, the range of plausible scenarios for future incremental tight gas production encompasses a year 2000 production rate of only 1 or at most 2 TCF/yr if conventional gas production remains at high levels or if gas markets do not rebound from their current slump, or a rate of 3 to 4 TCF/yr, or perhaps even somewhat higher, if there are major technology advances and a combination of strong markets and high prices for unconventional gas, the latter in response to disappointing prospects for conventional gas supply or a surge in gas demand.

[8]Over and above production from tight formations now being exploited. Current production is about 1 TCF/yr.

## GAS FROM DEVONIAN SHALES

### Definition

Devonian shale gas is gas produced from shales formed approximately 350 million years ago–during the Devonian period of geologic time–from the accumulation of organic-rich sediments in a shallow sea covering the eastern half of what now constitutes the continental United States. The first Devonian shale gas well was drilled in 1821, near Fredonia, NY, and moderate levels of gas production (recently somewhat less than 0.1 TCF/yr) have continued to the present. However, despite its long history, the Devonian shale resource is still considered "unconventional" because of its highly complex geology and because new technology and higher prices will be required to exploit the major share of its potentially recoverable gas.

## Resource Characteristics

The Devonian shales occur primarily in the Appalachian, Illinois, and Michigan basins, shown in figure 27. Past production has been primarily in a small portion of the Appalachian Basin, in the Big Sandy Field in Kentucky and adjacent West Virginia. The shales are highly variable in

**Figure 27.—Primary Area of Devonian Shale Gas Potential**


SOURCE Johnston & Associates, OTA contractor their makeup; they can be grouped according to color, with black and brown shales having higher organic content and gas content than the gray shales. The shales are a rich source rock for natural gas, but their porosity and permeability are very low compared to conventional gas reservoirs.[9] Consequently, gas content and flow rate also are low by conventional standards. Further complicating exploitation of the gas resource, the shales are sensitive to "formation damage''—an induced decrease in permeability—because they contain water-sensitive clays that can be dislodged by fracturing fluids and block pores and fractures.

Portions of the shale contain networks of natural fractures, which tend to be predominantly in a vertical pattern. These fractures also tend to be somewhat lined up rather than random in direction, a characteristic called "anisotropy." The fracture systems provide potential flow paths for shale gas.

The shale gas occurs as free gas in the fractures and pores of the shale and also as gas bound to the physical structure of the shale (adsorbed gas). The amounts and production mechanisms of the different modes of occurrence of gas are not fully understood, and this lack of understanding complicates estimation of the recoverable resource. A primary uncertainty is the contribution of adsorbed gas to total production. Most early estimates of shale gas resources are based on the notion that the primary source of producible gas is the free gas in the shale's fracture network. Recently, many in the research community have shifted to the view that gas adsorbed on the shale makes the major contribution to gas production.

## Technology

As with the tight sands, production of Devonian shale gas depends on well stimulation to overcome formation damage and the naturally low permeability of the reservoir and open up pathways for the gas to flow to the well bore. Unlike the tight sands, however, production using current technology generally cannot succeed unless the well intersects a natural fracture network, either directly or through an induced fracture. An important uncertainty is the extent to which new technological development will allow production from portions of the shale that do not contain a well-developed natural fracture network. Also unlike the tight sands, producers generally have used small fractures in the shales, a few hundred feet or less, not the massive 1,000-to 2,000-ft fractures becoming more popular in the Western tight sands.

Because of their extreme sensitivity to formation damage, the Devonian shales have been a primary target for the development of new fracturing techniques that avoid such damage. Stimulation by the use of explosives has been prevalent in the shales' production history, and more sophisticated explosive techniques may be promising for future development. Also, the shales have been a testing ground for new fracturing fluids, including gas-in-water emulsions, nitrogen, liquid carbon dioxide, and others. The gas-in-water emulsions, or foams, have dominated fracturing in the Devonian shales in recent years, but nitrogen has also grown in use for shallow wells because it does not cause formation damage. Nitrogen has limited ability to carry proppants, so it is less useful at depths where the induced fractures would close under the overburden pressure of the rock.

Fracturing has been extremely successful for many Devonian shale wells, but its overall record is very erratic. problems include extreme variation in the natural fracture systems from site to site, lack of a systematic scientific method in applying and evaluating fracture treatments, and difficulties in accurately locating the gas-bearing zones. An unfortunate result of the trial-and-error approach is that no scientific basis for selection of appropriate well stimulation techniques has been developed.

Aside from problems encountered in fracturing, development of the Devonian shale resource also is hindered by problems in exploration and well location. in general, sophisticated explora-

[9] Porosities generally are 1 or 2 percent compared to 8 to 30 percent in conventional reservoirs; permeabilities range from 0.001 to 1.0 md compared to 1 to 2,000 md in conventional reservoirs. The permeability difference means that, all else being equal, gas will flow 1 million to 2 million times faster in a conventional reservoir than in the Devonian shales.

tion technology, such as seismic reflection, is not used in shale development. Besides the technical problems, which include adverse terrain and lack of effectiveness of existing technology, the usual incentive for expensive geologic surveys—the ability to exclusively develop the surveyed area—is hampered by diverse land ownership and inadequate State regulatory systems that do not fully protect discovery rights.

## Resource Estimates

Several estimates have been made of the Devonian shale gas-in-place and recoverable resources. For example, recent estimates of the gas-in-place by the National Petroleum Council (1980), U.S. Geological Survey (1982), and Monsanto's Mound Facility (1982) encompass a range of 225 to 2,579 TCF for the Appalachian Basin, the most significant of the three shale basins by far. Differences in the estimates are caused primarily by the following factors:

- the use of different boundary conditions for inclusion in the estimated gas-in-place resource;
- including or excluding the less productive gray shales;
- substantial differences in the shale thickness calculations because the measurement techniques were different;
- varying levels of geochemical analysis undertaken (this analysis can identify areas where temperature and pressure conditions were poor for gas formation and preservation); and
- different views about the amount of gas in each "mode" of occurrence within the shale (in fractures, in micropores, or bound to the shale), and the extent to which it is properly measured in available studies of gas content.[10]

Although no consensus about all of these factors currently exists, OTA considers it likely that the Devonian shale gas-in-place is large, at least 500 TCF and more likely well over 1,000 TCF. The size of the in-place resource is not really the major issue, however, Because, in general, the shale is a low-quality gas resource and economic returns will be low, the major issue is the size of the **economically recoverable** resource.

Table 32 shows seven different estimates of Devonian shale recoverable resources. The estimates are not easily comparable because of differences in technology and economic assumptions, but they appear to display a fairly broad range of expectations about future shale gas development. For example, the 1977 OTA study estimates a

[10]Recent studies have indicated that most gas content measurements must be adjusted to account for gas that has escaped from the shale samples prior to measurement.

**Table 32.—Devonian Shale Recoverable Resource Estimates (TCF): Appalachian Basin**

| Organization | Year | Estimate | Conditions |
|---|---|---|---|
| Office of Technology Assessment | 1977 | 15-25 | After 15 to 20 years |
| | | 23-38 | After 30 to 50 years |
| | | | At $2-$3/MCF (1976$), current technology (borehole shooting or hydrofracturing), 150-acre spacing |
| Lewin & Associates | 1978-79 | 2-1o | Base case |
| | | 4-25 | Advanced case for prices between $1.75-$4.50 |
| | | Traditional - Advanced | |
| National Petroleum Council | 1980 | 3.3 - 38.9 | For price levels between $2.50-$9, 160-acre spacing |
| | | 15.3 - 49.9 | Technically producible |
| Pulle and Seskus (SAI) | 1981 | 17-23 | "Shot" wells, 160-acre spacing |
| Zielinski and Mclver (Mound) | 1982 | 30-50 | For States of West Virginia, Ohio, and Kentucky only, "shot" wells, 160-acre spacing |
| Lewin & Associates | 1983 | 6.2-22.5 | Technically recoverable, for most promising formations in Ohio. Maximum represents 80-acre spacing, advanced technology |
| Lewin & Associates | 1984 | 19-44 | Technically recoverable, for most promising formations in West Virginia. Preliminary values |

SOURCE" Off Ice of Technology Assessment large recoverable resource–up to 40 TCF–at moderate prices and using conventional technology. The 1977 Lewin study and the NPC study are considerably more pessimistic for similar technology/price conditions, with estimates centering on about 10 TCF or lower. [11] Both Lewin and NPC expect sharp increases in recoverable resources with higher gas prices and improved technology, however. Lewin, for example, projects a rough doubling of recoverable resources through advanced technology that allows a sharp reduction in dry holes, completion of multiple zones through each well, and more effective fractures. And NPC projects a similar doubling of resources as prices move from the $2.50 to $5.00/MCF range to the $5.00 to $9.00/MCF range. Finally, recent studies by Lewin of currently producing portions of the shale in Ohio and West Virginia, using a new reservoir simulation model, indicate that a substantial increase in gas recovery can be obtained with improved fractures, reduced spacing of wells, and more efficient well placement that take account of the shale's low permeability and anisotropy.

Aside from differences in assumptions about future gas prices and other economic conditions, differences in estimates of Devonian shale gas recoverable resources arise from several technical uncertainties. One type is the set of geological uncertainties that underlie differences in the gas-in-place estimates, as described previously. Other uncertainties are associated with the:

- ability of new stimulation technologies to immediately increase the flow rate and maintain an economic rate over the long term;
- ability of new exploration techniques to overcome the problems of finding areas with well-developed natural fracture networks;
- ability of advanced well-logging techniques to accurately identify gas-bearing zones and allow greater stimulation success;
- development of production techniques that will allow economic production from shale formations that do not have a well-developed fracture network; and
- the extent to which methane bound to the shale matrix plays a major role in production.[12]

[n **OTA's view, all of the existing studies that estimate recoverable shale gas resources for specified gas prices and technologies have significant methodological and/or data shortcomings. For example, because of data limitations, the 1977 OTA** study did not undertake a quantitative analyis of the geology of the Appalachian Basin; instead, it was forced to assume that 10 percent of the basin area would allow gas production at levels similar to the small area now under production. The early Lewin study evaluated recoverable resources using the assumption that most of the recoverable gas was fracture gas, an assumption now being challenged. And the NPC study uses an empirically derived equation for calculating the recoverable gas that does not include several variables—e.g., fracture density and thermal maturity of the shale—that appear to be critical to the existence of recoverable gas. However, the recent Lewin analyses do combine a detailed reservoir simulation approach with the latest available data, and probably should be considered the most credible analyses to date. Based on our interpretation of the Lewin work, **OTA considers it plausible that moderate increases** in gas prices coupled with a vigorous research program to improve well stimulation, well diagnostics (e.g., logging), and exploration techniques and to advance the state of knowledge of shale geology and production characteristics could yield substantial quantities of recoverable gas from the Devonian shales in the Appalachian Basin, Although the level of uncertainty associated with any estimate is high, a figure of 20 to 50 TCF for the recoverable resources in the fractured portions of the basin seems reasonable, assuming prices somewhat higher than today's (perhaps $5/MCF), optimization of fracturing technology currently in development, and easing of institutional barriers to development (including rationalization of well spacing rules). **A** combination of still higher prices–in the range of **$7** to $10/MCF–and advanced technology might boost the recoverable

[11] However, the Lewin estimate is predicated on a higher discount rate because of its perception of higher risk.

[12] A major role in production for adsorbed gas implies a substantially increased gas resource.

**resources to the 80 to 100 TCF level or higher. Development of methods to produce gas economically from shales that do not contain well-developed natural fracture systems could substantially increase the recoverable gas resource still further; however, it is important to recognize that the problems associated with developing these unfractured shales may be insurmountable.**

### Production Estimates

As with the tight gas analyses, those studies that projected future production from Devonian shales did so by relying on "educated guesses" about available rigs and well drilling rates. All of the Devonian shale studies concluded that production within the next few decades would be limited to relatively moderate levels. For example, the 1977 OTA study concluded that 1.0 TCF/yr could be achieved 20 years after commencing an intensive drilling program. The first Lewin study projected a maximum production rate of 0.9 TCF/yr in 1990 with advanced technology and $4.50/MCF gas in 1977$ ($7.00/MCF in 1983$), but this was predicated on starting the development effort in the late 1970s. Also, the Lewin study projected a maximum rate of only 0.3 TCF/yr with currently available technology. Finally, the NPC study projected a high of about 1.4 TCF/yr in 2000 with advanced technology and very high gas prices ($9/MMBtu in 1979$). At prices more in line with today's, however, production would have been only a fraction of this.

Development of the Devonian shales will be critically dependent on market conditions, which today are distinctly unfavorable to rapid advances in production and certainly have delayed the development schedules projected in the early studies. Furthermore, a rapid buildup of production would be hindered by institutional problems, divided land ownership, and difficult terrain. On the other hand, the most recent Lewin studies of Ohio and West Virginia conclude that advanced extraction technology and improved well placement could substantially increase individual well productivity and total recoverable resources. This implies a potential for a rapid buildup of production under the right price and technology conditions. if market conditions improve very soon and exploration and production technology advances are achieved, OTA considers a production rate of 1.0 to 1.5 TCF/yr from the Devonian shales by the year 2000 or soon thereafter to be plausible, although optimistic.

## COALBED METHANE

### Definition

Coalbed methane is natural gas formed as a by-product of the coal formation process and trapped thereafter in the coal seams. Unlike gas from tight sands and Devonian shales, past production of coalbed methane has been very low.[13] However, some important commercial recovery operations have begun in New Mexico's San Juan Basin, in Alabama's Warrior Basin, and elsewhere. Also, in the United States roughly 80 billion cubic feet (BCF) of coal gas is deliberately vented to the atmosphere each year from working coal mines, to remove the danger of explosion created by the buildup of methane concentrations in the mine shafts.

[13] However, gas formed in coal seams and trapped in adjacent formations has been produced in quantity.

### Resource Characteristics

Methane is found in all coal seams, although its amount per unit volume or weight of coal tends to be proportional to the rank (carbon content) of the coal: higher rank coals such as anthracite and bituminous coals may have from 200 to 500 cubic feet of methane per ton of coal, whereas the lowest rank lignite may contain 30 to 100 cubic feet per ton (CF/t). Gas content also increases significantly with depth; Kuuskraa and Meyer, in their analysis of coalbed methane gas-in-place, assign an average gas content to bituminous coal of 150 CF/t for 1,000 to 3,000 ft depths, and 400 CF/t for depths greater than 3,000 ft.[14]

The methane is found either adsorbed to the coal surfaces-by far the most abundant source—or trapped in the coal's natural fracture system, or "cleat.' The fracture system tends to be aligned so that, in an idealized form, the fractures resemble a series of vertical, parallel slices made in a block of coal—the "face cleats' '—with another, less well-developed series of vertical slices, the "butt cleats, " perpendicular to the face cleats. Because most coal beds are aquifers, water is also present in the fracture network, and its hydrostatic pressure plays a key role in keeping the methane from desorbing from the coal.

## Technology

Because coal is essentially impermeable, methane production depends on intersecting the natural fracture network to provide pathways for the gas to flow to the well. **A** second condition necessary for economic levels of production is to promote the resorption of the gas from the coal into the fracture system by reducing the pressure in the fractures. This usually involves dewatering the coal to reduce hydrostatic pressure. Because the rate of resorption is not a linear function of pressure–as reservoir pressure drops, resorption may remain low until a critical pressure is reached, and then accelerate rapidly as the pressure drops further-effective gas recovery may require drilling wells on relatively close spacing and pumping water from them rapidly and simultaneously in order to maximize the pressure drop. This production method will also help to outrun water infiltration into the coal seam. This practice of close spacing is in sharp contrast to the wide spacing used in conventional gasfields, because the close well spacing tends to reduce recovery per well in conventional fields.

A variety of methods can be used to enable wells to intersect the vertically oriented natural fracture network. Horizontal wells may be drilled from within a working mine or a specially drilled shaft. The latter method is extremely expensive, however. Vertically drilled wells may be slanted towards the horizontal, ideally so as to run parallel to and within the coal seam. Keeping the well within the seam is difficult, however, and there are substantial operating problems leading to increased costs. Hydraulic fractures also can be used to connect the well bore to the fracture system. However, induced fractures in the coal seams tend to be short and tend to parallel rather than intersect the planes of the natural fractures. in minable seams, the tendency of the fractures to propagate vertically may result in damage to the rock above the seam, a potential hazard to future mining. Finally, a variety of problems associated with well dewatering, formation damage, etc., still face future efforts to recover coal seam methane. Although for the most part these problems appear to be a matter of refining and upgrading existing methods and technology rather than accomplishing major innovations, considerable basic research is required to understand the controlling gas production mechanisms, develop an exploration rationale for identifying attractive drilling sites, and develop advanced well stimulation technology.

## Resource Estimates

Gas-in-place estimates for coal seam methane have been made by a variety of analysts and organizations, including most recently the Gas Research Institute (1980), National Petroleum Council (1980), Kuuskraa and Meyer (KM) of Lewin & Associates (1980), and the Department of Energy (1984). These and others are shown in table 33.

The three 1980 studies all use basically the same method—to multiply USGS-derived estimates of coal tonnage, subdivided according to rank, by estimates of gas content for each rank. The narrow spread of estimates–398 TCF (N PC) to 550 TCF (KM) —reflects the methodological similarity. These estimates should be considered as quite crude, because the available data on gas content are limited and variable, and the USGS estimates of deep coal resources below 3,000 ft—particularly important because gas content increases with depth—are uncertain.

[14] V. A. Kuuskraa and R. F. Meyer, "Review of World Resources of Unconventional Gas, " IIASA Conference on Conventional and Unconventional World Natural Gas Resources, Luxenburg, Austria, June 30-July 4, 1980.

**Table 33.—Coalbed Methane Resource Estimates**

| Studv | Resource in place TCF |
|---|---|
| Department of Energy (1984) . . . . . . . | ***68-395*** |
| Kuuskraa and Meyer (1980) . . . . . . . . . | ***550*** |
| National Petroleum Council (1980) . . | ***398*** |
| Gas Research Institute. . . . . . . . . . . . . | ***500*** |
| Federal Energy Regulatory Commission (1978) . . . . . . . . . . . . . | 300-850 |
| Deul and Kim (1978) . . . . . . . . . . . . . . | 318-766 |
| Wise and Skillern (1978) . . . . . . . . . . . | 300-800 |
| TRW (1977 . . . . . . . . . . . . . . . . . . . . . . | 72-860 |
| National Academy of Sciences (1976) . . . . . . . . . . . . . . . . . . . . . . . . | ***300*** |

SOURCES Adapted from *AGA Gas* Energy Review, September 1982, and C W Byrer, T H Mroz, and G L. Covatch, "Production Potential for Coalbed Methane in U S. Basins," SPE/DOE/GRI Unconventional Gas Recovery Symposium, 12832 1984

**Table 34.—Comparison of Recoverable Resource Estimates (TCF)**

| ***Technically or economically recoverable* gas:** | | | | |
|---|---|---|---|---|
| KM | 40-60[a] | | | |
| NPC . : : : | $2.50 | $5.00 | $9.00 | |
| | 5 | 25 | 45 | 10% ROR[b] |
| | 2.5 | 20 | 38 | 15% ROR |
| | 2.0 | 17 | 33 | 20% ROR |
| GRI . . . . | $3.00 | $4.50 | $9.00 | |
| | 10-30 | 15-40 | ***30-60*** | |

aTechnically recoverable resource.
[b]Rate of return
SOURCE Office of Technology Assessment

The recent DOE study, a portion of its Methane Recovery from Coalbeds Project, is a basin-by-basin analysis targeting only the most likely gas-bearing seams in each basin. Although all basins are not included and each individual basin estimate does not include all potential gas-bearing areas i n that basin, the focus on the most promising coal seams implies that the estimates may represent a good starting point for evaluating recoverable resources. However, the range of uncertainty in the multi-basin estimate, 68 to 396 TCF, was exaggerated by the method used to calculate the extremes of the range.

Estimates of the recoverable resource base have been made by the NPC (1 980), KM (1980), and GRI (1981). A summary of results appears in table 34. The GRI estimate is the result of a poll of experts. The NPC estimates are derived by first differentiating the gas-in-place resource according to estimated production levels (million cubic feet per day per well), and then comparing per well revenues at any given price to the estimated costs of an ''average' well in order to determine whether the gas is economically recoverable at that price. Uncertainties in the NPC results stem from a series of very broad assumptions about gas content, recovery efficiency, the relationship between coal seam thickness and gas production, the expected long-term production behavior of gas wells in coal beds, and several other factors. An important criticism of the NPC analysis is that it relies for its data base on isolated, previously drilled wells that are considerably less productive than new wells drilled according to the modern practice of close pattern drilling, and thus is too pessimistic. OTA concurs with this criticism but feels that the other areas of uncertainty, some with less predictable effects, are at least as important.

The Kuuskraa and Meyer analysis differs substantially from the others in that it uses an analytic model of gas production from coal seams, treating production as a simple diffusion process. The results are extremely sensitive to assumptions about the spacing of the vertical fractures in the coal seam and the magnitude of the diffusion constant. Also, while simple diffusion may be the controlling factor in some coal beds, it is likely in most cases that the actual physical process is considerably more complicated and the simple model used in the analysis will yield only very approximate results.

In OTA's opinion, none of the existing analyses provide an adequate basis for reliably estimating the size of the coal bed methane recoverable resource. It is possible that recent basin analyses sponsored by DOE might provide enough new basic data to form a basis for a more credible estimate of recoverable gas. However, it is not clear that we have sufficient understanding of the production mechanisms to provide a truly new, credible estimate as yet. Because of this lack of understanding, an estimate of recoverable resources that attempted to encompass the credible resource possibilities would have to span a wide range, probably on the order of 20 to 200 TCF or so.

## Production Estimates

**Both NPC and GRI calculated annual production estimates based on assumed drilling schedules. The NPC estimate assumes a continuously rising gas price from the present to 2000, with prices reaching as high as $9/MMBtu** (in 1979$) by 2000. **production is projected to peak at more than 2 TCF/yr in the late 1990s.** The GRI estimates are both price and technology dependent. At $3/MCF (1979$) and using existing technology, only 0.3 TCF/yr of production is projected for the year 2000. At $6/MCF and advanced technology, 1.4 TCF are projected,

The level of uncertainty associated with these estimates is very high. The physical character of the resource base is highly variable, so that past experience, which is limited anyway, cannot serve well as a guide to future production, The physical mechanisms controlling gas production from coal seams are not well understood. Furthermore, there are important uncertainties concerning legal ownership of the gas, environmental constraints associated with water disposal, unresolved mine safety issues, and other factors that may serve to constrain future gas development; the effects of these factors is difficult or impossible to predict.

On the other hand, successful development efforts such as U.S. Steel's effort in the Black Warrior Basin and others provide encouragement that coal seam methane could prove to be an important future gas source. Estimates projecting production of 2 TCF/yr by 2000 may seem excessive from our present vantage point but conceivably could become more credible with **advanced technology and strong demand.** Key targets for technology development and research include characterization of the deep coal resource, improvement of fracturing technology and deviated drilling technology, and improved understanding of the geologic characteristics affecting gas recovery, leading to a reliable estimate of the recoverable resource.

Chapter 8

# Tight Gas

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# Chapter 8
# Tight Gas

## INTRODUCTION

"Tight gas" is natural gas that is found in rock formations of extremely low permeability. Such low-permeability formations are found in all gas-producing basins in the United States. Depending on the volume of gas-in-place and the economic viability of its extraction, tight gas formations may constitute a large potential gas resource.

Because of the low permeabilities, fluid flow (both gas and liquid) through tight gas formations is highly restricted. Commercial volumes of gas can only be recovered by artificially fracturing the rock to increase the area of the reservoir in contact with the wellbore. Considerable difficulties in measuring key reservoir parameters in tight formations and establishing the productive areas and zones leads to high uncertainty about the commercial viability of the well until after an expensive fracturing treatment is completed and the well has produced for some time.

The tight gas resource, of all the unconventional natural gas resources, is thought to have the most potential for contributing to U.S. supply in the next 20 years. Low levels of gas have been produced from tight gas formations for many years; significant development began in the early 1970s with the successful use of massive hydraulic fracturing techniques in the Wattenberg Field in Colorado. Incentive prices established in 1979 by the Natural Gas Policy Act (NGPA) increased the relative attractiveness of the resource and promoted development in the early 1980s. Since then, however, interest in gas production from this difficult resource setting has declined as price levels for tight gas dropped in response to the current supply surplus.

## CHARACTERISTICS OF THE TIGHT GAS RESOURCE

Tight gas formations are defined in this report as low-permeability sandstone, siltstone, silty shale, and limestone[1] formations deposited in continental, shoreline, or marine environments. Earlier studies have used the terms "tight sands" or simply "tight" formations in addition to tight gas to refer to this resource. Some of the early studies included Devonian shales as tight gas formations, but later studies dealt with the shales separately because of their different production mechanisms and characteristics. This chapter also excludes Devonian shales from the "tight gas" category, treating them in chapter 9 as a separate unconventional resource.

Tight gas reservoirs represent the low permeability end of a continuum of gas-producing reservoirs rather than a unique type. In the past, the cutoff between a conventional and a tight gas reservoir has been somewhat arbitrary, based primarily on the economics of production or requirements for special production techniques. The permeability levels used to define the upper boundary for tight gas have ranged from 0.01 millidarcy (md)[2] to 1 md; most formations identified as tight have permeabilities less than 0.1 md. (For comparison, the permeability of cement is on the order of 0.001 red.) The granting of a special price incentive to tight gas under the NGPA **necessitated a more precise definition.** In 1978, the Federal Energy Regulatory Commission de-

[1] Except for the Edwards Lime formation in the Southwest, limestone formations have not been Included in tight gas resource assessments. John Sharer, Gas Research Institute, personal communication, 1984,

[2] A millidarcy, abbreviated as "red, " is a standard unit of permeability, which measures the ease with which fluids (liquids and gases) can flow through porous rock.

fined a tight gas reservoir as one having an average permeability of 0.1 md or less at subsurface (in situ) conditions of confining pressure and water saturation, and a maximum production rate prior to stimulation, dependent on depth, of 44 MCF/D at 1,000 ft up to 2,557 MCF/D at 15,000 ft.

The boundary between conventional gas and unconventional tight gas is still changing and will continue to change with changing economics and the further development of production technology for low-permeability reservoirs. Consequently, all estimates of resources and future production from tight formations must be evaluated in the context of their defined boundary conditions. Currently, the American Gas Association is reexamining its definition of the conventional/unconventional boundary. It appears likely that a result of this process will be to transfer resources from the unconventional to the conventional category. The subsequent decline in the projected tight gas potential actually would reflect the recognition that current technology can allow access to a substantial portion of this resource.

In evaluating the potential gas recovery from a well drilled into a tight gas formation, three questions need to be answered: 1) How much gas is present? 2) What conditions exist that control the flow of gas? and 3) Can extraction technology be successfully applied in this setting?

### 1) How Much Gas is Present?

The occurrence of gas in a given section of a formation is dependent on whether adequate source rocks and appropriate temperature conditions have existed which allowed gas to form. The ability of the gas to migrate and the presence of a trapping and a sealing mechanism are further requirements.

In the case of most tight gas reservoirs, the presence of interbedded organic shales or coal seams ensures an adequate source for gas formation, By the same token, migration is not a problem since the gas does not have to travel far. The low permeability of the formations themselves, together with the overlying shales or other sealing rocks, confine the gas within the sandstones. **In many areas, gas is being produced from nearby** conventional reservoirs, and the required temperature conditions may sometimes be inferred. However, any estimation of potential tight gas resources in unexplored areas should consider these temperature conditions as additional uncertainties.

Some of the tight gas formations deposited under shallow marine conditions, such as those in the Northern Great Plains, may represent an unusual type of natural gas occurrence. In these areas it has been suggested that the methane has formed biogenically (and at low temperatures and pressures) through decomposition of organic material by micro-organisms.[3] Biogenic gas formation allows gas to be present in areas that otherwise might be assumed not to be gas-bearing, because they have never been exposed to the higher temperatures and pressures generally associated with gas formation (see ch. 3).

Given that gas is present, the amount present in any portion of a tight gas formation is primarily a function of the porosity, temperature, and pressure. These parameters define the space available to be occupied by gas molecules and the amount of gas that can be found in each unit volume of available space. Water saturation is also an important criterion as water competes with gas for the available space.

**Porosity** is the fraction of the rock that is void **space,** i.e., the space remaining between and within mineral grains, after the grains are packed together. Dissolution and precipitation of material by fluids percolating through the rock may alter the original porosity. Porosity of tight gas formations typically ranges from 3 to 12 percent.[4] Conventional reservoir porosities range from **14** to 25 percent or more.

Pore size is an important determinant of the water saturation of the rock, and thus of gas volume. Very fine grained rocks such as siltstones and chalks, may have high porosities but the individual pores are very small, resulting in a high pore surface area to pore volume ratio. Water

[3] D. D. Rice and E. C. Claypool, "Generation, Accumulation, and Resource Potential of Biogenic Gas," *AAPG Bulletin,* vol. 65, No. 1, January 1981.

[4] That is, 3 to 12 percent of the rock volume is void space.

molecules may be adsorbed on pore surfaces, reducing the volume available to be filled by gas and increasing the water saturation. Because of small pore sizes, tight gas formations are generally characterized by high to very high water sat u rations.

## 2) How Well Can the Gas Flow?

The most important reservoir characteristic to consider in terms of the recovery of gas from tight gas formations is **permeability** because this ultimately controls how fast the gas can be produced. Permeability is a measure of the ease with which fluids can move through interconnected pores of the reservoir rock in response to a pressure gradient. Thus, a volume of rock can be both porous—have a high percentage of void space—**and** have very low permeability if the individual void spaces are not interconnected or the channels are too narrow to allow gas to move freely. Permeabilities of conventional gas reservoirs range from 1.0 md to several darcies (thousands of millidarcies). In contrast, the permeability of a tight gas reservoir can be as low as 0.00001 md (although at present, recovery generally is limited to reservoirs with permeability greater than about 0.007 red).

The low permeabilities of tight gas formations result from a combination of factors that close off connections between pores, including small grain size, high clay content, and the cementation of grains resulting from the precipitation of dissolved materials.

In very fine grained and recrystallized rocks, where connections between pores are very small, the level of water saturation is a key factor in determining relative gas permeability. Several studies have demonstrated that water saturations on the order of 60 to 70 percent can effectively reduce the permeability to gas to zero.

Clay content and composition in a formation is another important factor in determining its permeability. Many clays are formed after deposition and tend to grow in such a way as to block pores and pore throats. Certain types of clays are expandable on contact with freshwater. The large volumes of water introduced during drilling into **a** formation by drilling muds and fracturing fluids can cause such clays to swell, further reducing permeability of the formation. Gas and water flow can also reduce permeability by displacing and plugging openings with loosely aggregated or platey clays.

**All** the factors discussed above affect the matrix permeability of the reservoir rock itself, disregarding any faults or fractures. The **bulk permeability of the entire reservoir,** however, may be greater if there is a well-developed natural fracture system. Natural fractures occur as a result of unequally distributed stresses at any time during or after formation of the rock. They are ubiquitous in all rock formations and occur at all scales. Large fractures may extend for long distances, while microcracks are found at the scale of the smallest grain. At greater depths, under high overburden pressures, most small cracks and some larger fractures are closed. Deposition of crystalline materials by migrating fluids also can seal off fractures. s Nevertheless, the existence of natural fractures is extremely important to the net permeability of tight gas formations.

The flow of gas in tight formations is also a function of the shape of the reservoirs and their lateral continuity—whether or not they exist as continuous bodies spread over large areas or instead occur as multiple smaller, discontinuous units. Lateral continuity and geometry of gas-bearing units control how much gas can find a flow path to the wellbore. Most studies have responded to the differences in these characteristics among the various tight formations by subdividing the formations into two categories commonly referred to as blanket formations and lenticular formations.

**Blanket formations** consist of continuous gas-bearing deposits that extend laterally over a large area. Blanket reservoir units, 10 to 100 ft thick, may be composed of sandstone, siltstone and silty shale, or chalk or limestone interbedded with very low permeability shales or non marine de-

‘However, if fractures form after hydrocarbons have displaced the water layer, the fractures usually remain open. The mineral saturated water is no longer present to precipitate solid crystals (Ovid Baker, Mobile Research & Development Corp., personal communication, 1984).

posits, including coal seams. Alternatively they can occur as millimeter to centimeter thick sand-rich layers, or "stringers," alternating with clay-rich layers. The bulk of current tight gas production is from reservoirs **in blanket formations.**

**Lenticular formations** consist of many relatively small, laterally discontinuous sandstone and siltstone units, or "lenses," intermingled with shales and sometimes coal seams. These units are similar in mineral composition to the blanket sandstones except that they tend to have higher clay contents. They **occur stacked vertically one over the other,** in formations hundreds of feet thick. The size, orientation, and geometry of the lenticular units are variable. For example, some, such as units formed by the filling of stream channels, are long and narrow and may have a preferred orientation. Other deposits formed at the bends of stream meanders tend to be shorter and wider and more randomly oriented.

The discontinuous nature of lenticular formations and the variable geometry of the lenses makes them a more difficult resource to quantify, in terms of both gas-in-place and potential for recovery, **For these reasons, despite their extensive occurrence, they have only recently been targeted as a potential resource.**

### 3) How Will Technology Perform?

The third critical variable for economic recovery of tight gas is the viability of massivescale well stimulation and other extraction technologies **in the geological settings containing tight** gas. Here the issues encompass a large number of specific technology issues ranging from the ability to identify, using well logs, the attractive zones for gas recovery, to developing fluid systems that can help contain a large vertical fracture within a given rock interval. While work is progressing in these areas, much new research and development is required before efficient technologies will exist for tight gas extraction. The key technologies are discussed later **in this chapter.**

## GAS-IN-PLACE ESTIMATES[6]

**A** number of estimates have been made of the resource base and production potential of tight gas formations, beginning in 1972 with the Federal Power Commission's (FPC) National Gas Survey report. In 1978, the Federal Energy Regulatory Commission's (FERC) report updated and expanded on the FPC estimate of the tight gas resource. In 1978 and 1979, Lewin & Associates (Lewin), under contract to the Department of Energy, made a detailed appraisal of 13 tight gas-bearing basins. In 1980, the National Petroleum Council (N PC) published its extensive study on the total U.S. resource in tight formations, combining resource estimates **for 12 basins that had undergone an extensive appraisal, and 101 additional basins whose estimates were based on extrapolation from the appraised basins.** Finally, in 1984, the Gas Research Institute conducted a series of sensitivity analyses of the tight gas re**source base, based** on the NPC methodology.

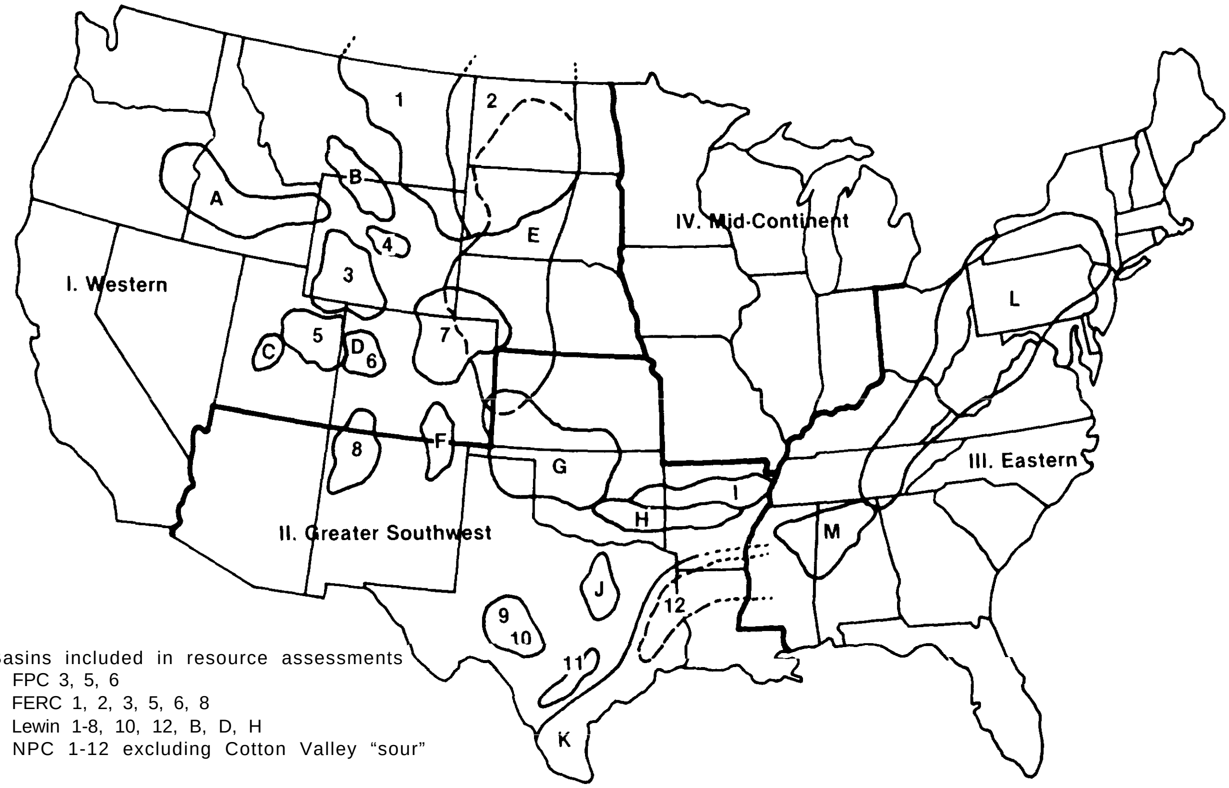
**Early estimates** of **the tight gas-in-place by the** FPC and FERC only determined the resource **for specific basins. Subsequent estimates expanded the number of basins under consideration and undertook more detailed appraisals within the individual basins as more data became available. The basins included in the various studies are shown in figure** 28. A chronologic representation of the changing resource estimates **for the appraised basins** is given in table 35. Note **that increasing the area under consideration has not necessarily increased the estimated size of the resource.**

### Methodologies

The FPC and FERC studies defined the amount of gas within a unit reservoir volume by estimat-

6 In this section, and the section on recoverable resources later in the chapter, OTA has chosen to emphasize the 1980 National Petroleum Council Study on Tight Gas in its discussions of previous resource estimates. This emphasis is based on the excellent reputation of the NPC report, which is widely cited in discussions of the tight gas resource and future production potential, the report's extensive documentation of assumptions and methodology, and the fine level of detail in the basin and subbasin analyses.

**Figure 28.—Primary Tight Gas Basins**




Basins included in resource assessments
FPC 3, 5, 6
FERC 1, 2, 3, 5, 6, 8
Lewin 1-8, 10, 12, B, D, H
NPC 1-12 excluding Cotton Valley "sour"

1. Western Region
1. Northern Great Plains
2. Williston
3. Greater Green River
4. Wind River
5. Uinta
6. Piceance
7. Denver
A. Snake River
B. Big Horn
C. Wasatach
D. Douglas Creek
E. Western Shallow Cretaceus Trend

II. Greater Southwest Region
8. San Juan
9. Val Verde-Ozona Trend
10. Val Verde-Sonora Trend
11. Edwards Lime Trend
12. East Texas/North Louisiana Basin—Cotton Valley Trend
F, Raton
G. Anadarko
H. Ouachita
1. Arkoma
J. Fort Worth
K. Western Gulf Coast

III. Eastern Region
L. Appalachian
M. Black Warrior

NOTE Coastal regions include offshore areas
SOURCE National Petroleum Council

ing average gas-filled porosity[7] and average reservoir temperature and pressure conditions for each of the formations or sections of formations that they evaluated. Using these figures together with the net "pay" (i. e., gas-bearing) thickness and the total productive area of the formation, each study team calculated the total gas-i n-place in the reservoir.

The FPC, in its 1972 study, set minimum criteria defining its interpretation of gas that could conceivably be considered as recoverable. It restricted its evaluation to reservoirs with a minimum net pay thickness of 100 ft, less than 65 percent water saturation, 5 to 15 percent porosity, and permeabilities of 0.05 to 0.001 md. It included only formations at depths between 5,000 and 15,000 ft and defined a minimum reservoir size of 12 square miles. It also only considered

[7] Total porosity times the fraction of void space filled with gas.

reservoirs in remote areas, and, among these, only reservoirs not interbedded with high-permeability aquifers.[8] Its study concluded that the three Rocky Mountain Basins alone contained some 600 TCF of tight gas (table 35).

The FERC study used the same methodology as the FPC to calculate the gas-in-place but revised some of the criteria and expanded the area evaluated to include the San Juan Basin and the Northern Great Plains. They included formations with thinner pays (to 20 ft thick) and depths as shallow as 1,500 ft, and allowed lower gas-filled porosities. Despite the expanded area and modified formation parameters, the size of the tight gas resource only increased from 600 to 793 TCF (table 35).

Both the FPC and the FERC recognized that tight gas resources probably existed in other gas-bearing basins. Since little data existed in these areas, however, they felt the size of the additional resource could not be properly evaluated.

The Lewin and NPC studies used considerably more elaborate methodologies to calculate the gas-in-place. Their methods were designed to take into account the variability of physical proper-ties, such as permeability, porosity, and net pay (total thickness of gas-bearing zones), within a format ion.

The Lewin study used available well data to divide each formation into "subareas" based on homogeneous physical characteristics. The potentially productive portion of each subarea was determined by multiplying by the wildcat success rate (fraction of wildcat wells that are commercial successes) for that region, The volume of gas-in-place calculated for each subarea was further adjusted to reflect a log-normal distribution of "pay quality."[9] The Wattenburg Field in the Denver Basin, a relatively well-developed tight sands gasfield, was used as a model to determine a characteristic distribution of pay qualities.

The NPC methodology for calculating the gas-in-place in its appraised basins was similar to the Lewin approach. Instead of using the same pay quality distribution across all fields, however, the NPC determined a distribution of pay quality and other reservoir properties for each individual basin or subbasin based on existing well data. In this way it could calculate the gas-in-place for up to six permeability levels. The NPC study also evaluated a slightly larger area (13,000 more

[8] These last two criteria were included because nuclear explosives were being considered as a stimulation mechanism. The FPC excluded large portions of known tight gas resources which occurred in more populated areas. The FERC study removed these exclusions because by 1978 it seemed evident that nuclear explosives would not be used.

[9] In the Lewin report, pay quality is a function of porosity, permeability, and thickness of the gas-bearing zone.

**Table 35.-Tight Gas-in-Place Estimates (in TCF)**

| Appraised basins | FPC 1973 (gas-in-place) | FERC 1978 (gas-in-place) | Lewin1978 (gas-in-place) | NPC 1980 (gas-in-place) |
|---|---|---|---|---|
| Northern Great Plains/ | | | | |
| Williston | — | 130 | 74 | 148 |
| Greater Green River | 240 | 240 | 91 | 136 |
| Uinta | 210 | 210 | 50 | 20 |
| Piceance | 150 | 150 | 36 | 49 |
| Wind River | — | — | 3 | 34 |
| Big Horn | — | — | 24 | — |
| Douglas Creek | — | — | 3 | — |
| Denver | — | — | 19 | 13 |
| San Juan | — | 63 | 15 | 3 |
| Ozona | — | — | — | 1 |
| Sonora | — | — | 24 | 4 |
| Edwards Lime | — | — | — | 14 |
| Cotton Valley "sweet" | — | — | 67 | 22 |
| Cotton Valley "sour" | — | — | 14 | — |
| Ouachita | — | — | 5 | — |
| Total | 600 | 793 | 423 | 444 |

square miles) of potentially productive land than Lewin, although the two sets of appraised basins were similar (Lewin appraised 10 of the 12 NPC basins). In addition, the Lewin study did not evaluate gas-in-place for permeabilities less than 0.001 md, whereas the NPC study included a number of areas with permeabilities as low as 0.0001 md and some areas with permeabilities as low as 0.00001 md. Despite these differences, however, the Lewin and NPC reports do not differ substantially in their total estimates of gas-in-place in the appraised basins (423 v. 444 TCF, respectively). On the other hand, the estimates for individual basins do differ considerably.

In addition to the 12 basin appraisals, the NPC study made the first attempt to estimate the total tight gas resource occurring in all gas-producing basins in the Lower 48 States. To do this it extrapolated the results of its detailed basin appraisals to 101 remaining potential gas-bearing basins. Extrapolated basins were classified according to their similarity to appraised basins; certain formations in the appraised basins were chosen as analogs to formations in the extrapolated basins. The NPC estimated an additional 480 TCF in place in the extrapolated basins as shown in table 36. Its total gas-in-place resource estimate for the U.S. Lower 48 States is 924 TCF.

## Estimate Comparison and Discussion of Uncertainties

### Appraised Areas

The sequence of gas-in-place estimates for tight gas represents a continuing refinement of the estimation process. Each estimate builds on the former–adding new data and evaluating new areas. In general, the more detailed analyses have tended to produce lower gas-in-place estimates for a particular area. For example, the early FPC and FERC estimates of gas-in-place for the Uinta Basin are 150 TCF. The later Lewin and NPC estimates for the Uinta are only 50 and 20 TCF, respectively. These reductions can be in part accounted for by an increasing realization of high water saturation in the tight gas reservoirs and its negative effect on both gas content and gas permeability.[10] As discussed above, high water saturations tend to reduce the total volume of gas in the reservoir rock as well as restrict the gas flow. The NPC study also reduced the assumed thickness of total pay intervals in the Uinta from a 500- to 1,000-ft range to less than 500 ft, reducing the overall volume of the gas-producing zone and thus the total gas-in-place.

**Table 36.—National Petroleum Council's Gas-in-Place Estimates**

| | Appraised (12 basins) | Extrapolated (101 basins) | Total (113 basins) |
|---|---|---|---|
| Potential productive area (square miles) | 53,000 | 68,500 | 121,500 |
| Gas-in-place (TCF). | 444 | 480 | 924 |

SOURCE NPC Reporl vol V part I table 1

The NPC estimate represents the most comprehensive estimate of the gas-in-place resource base that exists to date. Because of its level of detail and its attempt to include gas in all gas-bearing basins, it probably represents the best available quantitative assessment of the size of the gas-in-place resource for tight gas. It shares, however, a drawback common to all the estimates: in OTA's opinion, none of the estimates adequately quantifies the extent of the uncertainty associated with the gas-in-place calculation.[11] This may result in the impression that the gas-in-place has been very narrowly defined, whereas the actual range of uncertainty may be quite large.

In most cases the estimators were fully aware of factors contributing to uncertainty. To the extent that their estimates are used by producers and others familiar with the industry, the level of uncertainty may be understood. When the estimates are to be used by those without such a common background, the inherent uncertainties need to be explained in some detail. The following discussion describes the important factors

[10] Strictly speaking, permeability does not affect the magnitude of gas-in-place, whereas gas *content* most certainly does. However, most estimates of gas-in-place do not attempt to Include every molecule of gas, and may exclude gas from formations that have no recoverable gas. Because permeability *does* affect recoverability, an altered estimate of permeability may cause a change In estimated gas-in-place. Nevertheless, gas content is the more closely related of the two variables to gas-in-place.

[11] This statement is not meant to imply that the NPC report did not discuss uncertainty. To the contrary, the technical reports presented substantive discussions of the uncertainties in key parameters, and used probability distributions rather than point estimates in several key calculations. However, these discussions and calculations were not translated into error bands around the report's projections of resources and future production.

contributing to uncertainty and their implications for gas-in-place estimates.

Differences and uncertainties in volumetric estimates of the tight gas resource are often a function of the level of understanding of the geologic history of the basins and the physical characteristics of the formations. Critical parameters include the porosity and water saturation, the areal extent and thickness of the gas-producing portion of a formation, and the actual presence of gas and its geologic origins.

As discussed earlier, porosity and water saturation constrain the amount of gas present in a discrete volume of rock. However, these parameters are extremely difficult to measure accurately and may vary over a wide range within a small area, Available data consist of extrapolations from existing wells and are often insufficient for a valid statistical analysis of a potential producing formation. Furthermore, conventional techniques for measuring and interpreting reservoir parameters, where they have been used in the tight gas intervals, are often not applicable to these types of formations. For example, conventional interpretation of well log data frequently results in higher measured porosities than those actually observed by laboratory analysis of core samples. Errors in porosity measurements can lead to even larger errors in computed levels of water saturation, compounding errors in the estimates of gas-in-place. In the last few years, interpretative techniques have been modified to apply specifically to low-permeability intervals, but these techniques are not yet routinely used.

The extent to which measurement problems of this sort have affected tight gas resource estimates is difficult to determine, although these problems are likely to have been acute for the earlier studies. I n the NPC analysis, well performance calculations for future wells were compared with actual well performance in producing wells to check the procedures for estimating porosity and permeability.[12] However, despite recent advances in logging systems and interpretation techniques, there still were severe measurement problems at the time the NPC estimates were developed. In fact, the discussion of measurement problems that appears in the NPC report itself, reproduced in box H, implies that the NPC analysts could not have been overly confident about the precision of their resource calculations.

The areal extent of some tight formations, particularly blanket formations, may be fairly well documented in developed basins from data collected from exploration and development wells drilled for conventional gas resources. Pay thickness may be fairly easy to determine for some blanket formations in which sandstone beds are clearly defined. I n other blanket formations, thin gas-bearing sand stringers occur finely interbedded with shales, making determination of the net productive thickness extremely difficult.

The lateral continuity, thus areal extent, of the gas-bearing portions of lenticular formations may be more difficult to determine than for blanket formations since the geometry of the individual lenses cannot be readily understood just by drilling and logging multiple wells within a formation. For example, sand-rich intervals occurring at approximately the same stratigraphic level in two or more wells may or may not represent the same lens (see fig. 29). Extrapolation from mapped surface features of these formations is the best way, at present, to determine dimensions, distribution, and orientations of the sand lenses. However, visible surface manifestations of lenticular formations are not always conveniently present. Another way to approximate the volume of lenticular tight gas formations is to determine an average sand-to-shale ratio based on well log data for a portion of the formation and extrapolate this over the area covered by the formation. The accuracy of this method depends on the number of wells drilled through the formation.

The presence of appropriate source materials and temperatures and/or biologic agents for hydrocarbon generation is a function of the geologic history of a basin. Many tight gas resource estimates consider a large portion of the tight gas interval in the Rocky Mountain Basins to be gas-bearing. There is, however, a dissenting opinion: that temperature, pressure, and source rock composition throughout many lenticular basins, such as the Piceance, were not appropriate for the gen-

[12] Ovid Baker, Mobil Research & Development Corp., personal communication, 1984.

**Box H.—What the NPC Report Had to Say About Measuring Key Tight Gas Resource Parameters**

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

**"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 v. 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.**

**"Net pay is one of the most important parameters required for reservoir performance evaluation . . . Current methods for determining net pay have a very high probability for error.**

**"Accurate knowledge of permeability is essential for , . . predicting potential well performance . . . Current methods for obtaining permeability . . . exhibit questionable reliability."**

SOURCE: National Petroleum Council, *Unconventional* Gas *Sources: Tight* Gas *Reservoirs,* Part 1, December 1980,

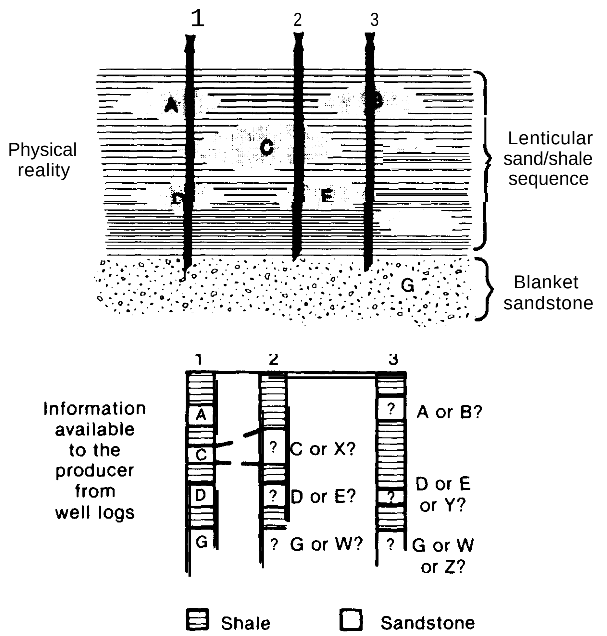
eration of large quantities of gas.[13] This opinion holds that only a small proportion of the thousands of feet of vertical section of tight sandstones is actually gas-bearing. If confirmed, this would substantially reduce the estimated gas-in-place, and make basins like the Piceance much less attractive for potential production. Similarly, the NPC estimate of the gas-in-place in the Denver Basin included a caveat that as much as 30 percent of the estimated gas-in-place in that basin may not actually exist. Temperature and pressure conditions in the northern part of the basin may never have been high enough to generate gas. The volumetric estimate of gas-in-place in the Denver Basin is based on gas contents extrapolated from the known gas-bearing portions of the formations occurring in the southern part of the basin.

The most controversial of the appraised areas is the Northern Great Plains, estimated by the NPC to have nearly 150 TCF of gas-in-place in shallow formations. Two-thirds of this gas is estimated to be technically recoverable. The controversy centers around the origin of the gas, whether it is early thermogenic or biogenic,[14] and

[13] J.W. Crafton, "Fracturing Technologies for Gas Recovery From Tight Sands," contractor report to OTA, September 1983.

[14] That is, formed by physical processes associated with high temperatures (thermogenic) or else by biological processes, usually anaerobic digestion (biogenic).

**Figure 29.—Problems With Reservoir Mapping in Lenticular Formations**




Note that A & B and D & E are stratigraphically at the same level, but are distinct units.

SOURCE: Office of Technology Assessment.

if biogenic, whether it formed during deposition and burial of the sediments in the basin (75 million to 100 million years ago) or more recently.[15] The theory accepted by the NPC, based on a study by the USGS,[16] is that it is old biogenic gas, and is ubiquitous throughout the region. Further, the NPC assumed that gas migration and loss to the atmosphere has not significantly depleted these resources.

As discussed in a dissent to the NPC estimate of Northern Great Plains gas-in-place, alternate theories of recent biogenic or early thermogenic formations imply a far lower volume of gas generated and only localized accumulation, implying in turn a lower gas-in-place, on the order of 10 to 20 TCF.[17] Even if the gas is old biogenic gas, some argue that there is likely to have been significant gas loss since the time of formation, unless sealing mechanisms have been unusually effective.

Given the large discrepancies in estimates of gas-in-place, and the important implications for the natural gas resource base, the questions associated with the origin of the Northern Great Plains gas and its preservation need to be resolved.

As might be expected, dissent from the NPC estimates is not restricted to those who are more pessimistic or are simply skeptical of the accuracy of the estimates. For example, several panelists at OTA's Workshop on Unconventional Gas Sources felt that the NPC's resource estimates reflected an **overly conservative approach** which tended to discount or dismiss resource potential unless there existed definitive evidence of its existence. It was claimed that, in some basins where extensive drilling records were available, NPC geologists assigned either zero or a heavily discounted value of gas-in-place to sections where there had been no "gas shows, " even when the "no shows" resulted simply from a lack of drilling. A case in point is the Denver Basin, mentioned previously; in this basin, the NPC assumed that only 1,600 of a total of 45,000 sections, or 3.6 percent, are gas-bearing. In the words of one of these critics, this approach "places an unjustified premium on the exploration technology and wisdom of our predecessors in the petroleum business."[18]

In the opinion of these same critics, the conservatism displayed in the NPC study's estimates of productive **area is duplicated** in its estimates of the **thickness** of the gas-bearing rock in the productive formations. For example, in the NPC analysis of the Piceance Basin, one of the lenticular basins where high gas-in-place estimates have been questioned, the four gas-bearing formations have a total thickness averaging about 6,400 ft but are assigned estimated "net pay ranges, " or gas-filled thicknesses, of:

| *Formation* | Net *pay range (ft)* |
|---|---|
| *1.* Ft. Union. . . . . . . . . . . ... . . . . | 12-80 |
| 2. Corcoran Cozette . . . . | 16-70 |
| 3. Mesaverde. . . . . . . . . . . . . . . . | 20-200 |
| 4. Lower Cretaceous-Jurassic . | 7-35 |

[15]If formed recently, less gas would be expected because the conditions necessary for methane-forming bacteria to reach underground sediments are not commonly available. National Petroleum Council, *Unconventional Gas Sources, Tight Gas Reservoirs, Part II,* appendix, December 1980.

[16]D. D. Rice and G. W. Shurr, "Shallow, Low-Permeability Reservoirs of Northern Great Plains—Assessment of Their Natural Gas Resources," *AAPG Bulletin,* vol. 64, No. 7, July 1980, pp. 969-987.

[17]National Petroleum Council, *Unconventional Gas Sources, Tight Gas Reservoirs, Part II,* appendix, December 1980.

[18]Ovid Baker, Mobil Research & Development Corp., letter of Aug 3, 1984, to OTA.

The ranges are not additive, but **at no point does the NPC assume that the gas-filled portion of the formations occupy more than** 6 **percent of the total thickness of sediment.**

It is unlikely at this time that the existing arguments about the relative "optimism" or "conservatism" of the NPC's estimate of gas-in-place can be resolved. In OTA's opinion, **the** NPC **estimate of gas-in-place for the appraised basins, excluding the Northern Great Plains, probably should still serve as a reasonable "most likely" estimate, even though a considerable error band—at least +/- 100 TCF—must be assigned to the estimate. As for the Northern Great Plains, there appears to be a substantial possibility** that the NPC estimate is too high, but the evidence is by no means conclusive.

### Extrapolated Areas

In the NPC analysis, the uncertainties that apply to the appraised basins are magnified in the extrapolated basins. Not only is there a lack of exploration and production data for these basins, but also the gas-in-place estimates were not generated by geologists experienced in those basins, as was the case for the appraised basins. Extrapolations were made by assigning gas-in-place values to the estimated productive area in each extrapolated basin using formations in appraised basins as analogs. In some cases this approach has a high potential for error, since different parts of the country have undergone significantly different geological histories which may have affected the amount of gas formed and preserved, but which could not be properly accounted for in the estimation process.

For example, the Eastern region (primarily the Appalachian and Black Warrior basins) was estimated to contain 49 TCF in shallow formations based on analogies with formations in the Northern Great Plains. However, the Northern Great plains estimates assume a biogenic origin for the gas, leading to the large volumes of gas-in-place. Even if biogenic gas formed in the Appalachian and Black Warrior basins, given their age (300 million to 400 million years relative to 75 million to 100 million years) and complex geologic history, it is unlikely that much biogenic gas would have been preserved to the present day. Therefore, the gas content per unit rock appears unlikely to be the same in the two regions.

There was widespread agreement among the NPC study participants interviewed by OTA that the gas-in-place estimates for the extrapolated basins were highly uncertain.

## TECHNOLOGY

The characteristics of the tight gas resource base present gas producers with a variety of important problems in locating and exploiting this gas. Many of these problems result from the very low permeability of the tight gas reservoirs and the consequent need to use fracturing to achieve commercial levels of gas production. For example, full exploitation of the lenticular reservoirs requires the ability to contact lenses remote from the wellbore, yet our current ability to predict or control fracture length and direction is poor. In addition, the presence of water-sensitive clays raises the potential for formation damage from the fracturing fluids. Difficulties in accurately measuring reservoir characteristics greatly complicate fracture placement and add to the economic risk of stimulation. Also, the depth and structure of some of the tight formations lead to extremely demanding requirements for fracture fluids and proppants. In this section, these problems and the technologies available to overcome them are briefly discussed. A longer discussion of fracturing technologies is presented in appendix B.

### Hydraulic Fractures

Gas flows from a reservoir towards a well bore because of a pressure difference between the reservoir and the well bore. The rate of flow is dependent on the difference in pressure and the permeability of the formation. Fracturing is designed to increase flow rates by cracking the reservoir rock, exposing more of the reservoir surface to the lower wellbore pressure. Hydraulic fracturing is accomplished by pumping large volumes of fluid down the wellbore, increasing the pressure on the rock formation until it breaks down and fractures. Because the fractures would tend to close when the fluid is removed—especially in deep reservoirs where the pressure of the rock is great—sand or other materials are added to the fluid. Left behind when the fluid is removed, these "proppants" are wedged into the fractures and prevent them from closing,

Hydraulic fractures tend to be unidirectional, generally extending out in opposite directions from the wellbore. By convention, their length is measured along one wing (see fig. 30). Their direction and orientation (vertical, horizontal, or inclined) are controlled by the regional stress regime and the depth of the target formation. Induced fractures at depths greater than 2,000 ft are oriented in the vertical plane. At shallower depths, such as might be found in the biogenic gas reservoirs of the Northern Great Plains, fracture orientation may be horizontal.

Table 37 illustrates the need for fractures in tight formations and the substantial benefits that may be gained from larger fractures. As shown in the table, a well in a highly permeable (10 md) reservoir can drain all the gas in two sections, or 1,280 acres, of a field over a 15-year production life. An unfractured[19] well in a tight (0.001 md) blanket sand can drain only about 20 acres of the field during a 30-year production life, and during that time would average less than **40** MCF/D of gas production, a very low rate. A massive hydraulic fracture creating a 1,000-ft fracture would increase the average production rate by nearly fivefold and allow complete drainage of the field with six wells per section rather than nearly 30 with unfractured wells. An advanced technology producing a 4,000-ft fracture would increase the average production rate by a factor of 15 and allow the tight field to be drained with a 320-acre (two wells per section) spacing, a fairly common spacing in **conventional** gasfields.

Successful fracturing in tight formations is complex and faces substantial obstacles. A few critical points should be understood. First, the great majority of tight gas recovery heretofore has been restricted to areas "characterized by thick, fairly uniform, blanket-type formations , . . (where) . . . only a limited knowledge of the formation characteristics is necessary to stimulate economic production rates."[20] The majority of the resource, however, is more complex, and greater understanding of the geology and production mechanics is critical .21 Second, although fracturing dates from the 1800s, and **hydraulic** fracturing dates from 1947 and has the benefit of the experience gained by thousands of separate fracturing treatments, the type of massive hydraulic fracture needed to begin to fully exploit the tight resource has only been developed in the last 10 years or so. The process is not fully understood and extrapolation to new geologic situations is difficult.

[19]Actually, the process of "completing" the well involves an explosive perforation of the well lining that creates a small fracture, here assumed to be 100 ft in length.

[20]Gas Research Institute, *Status Report." GRI's Unconventional Natural Gas Subprogram,* December 1983,

[21]Ibid.

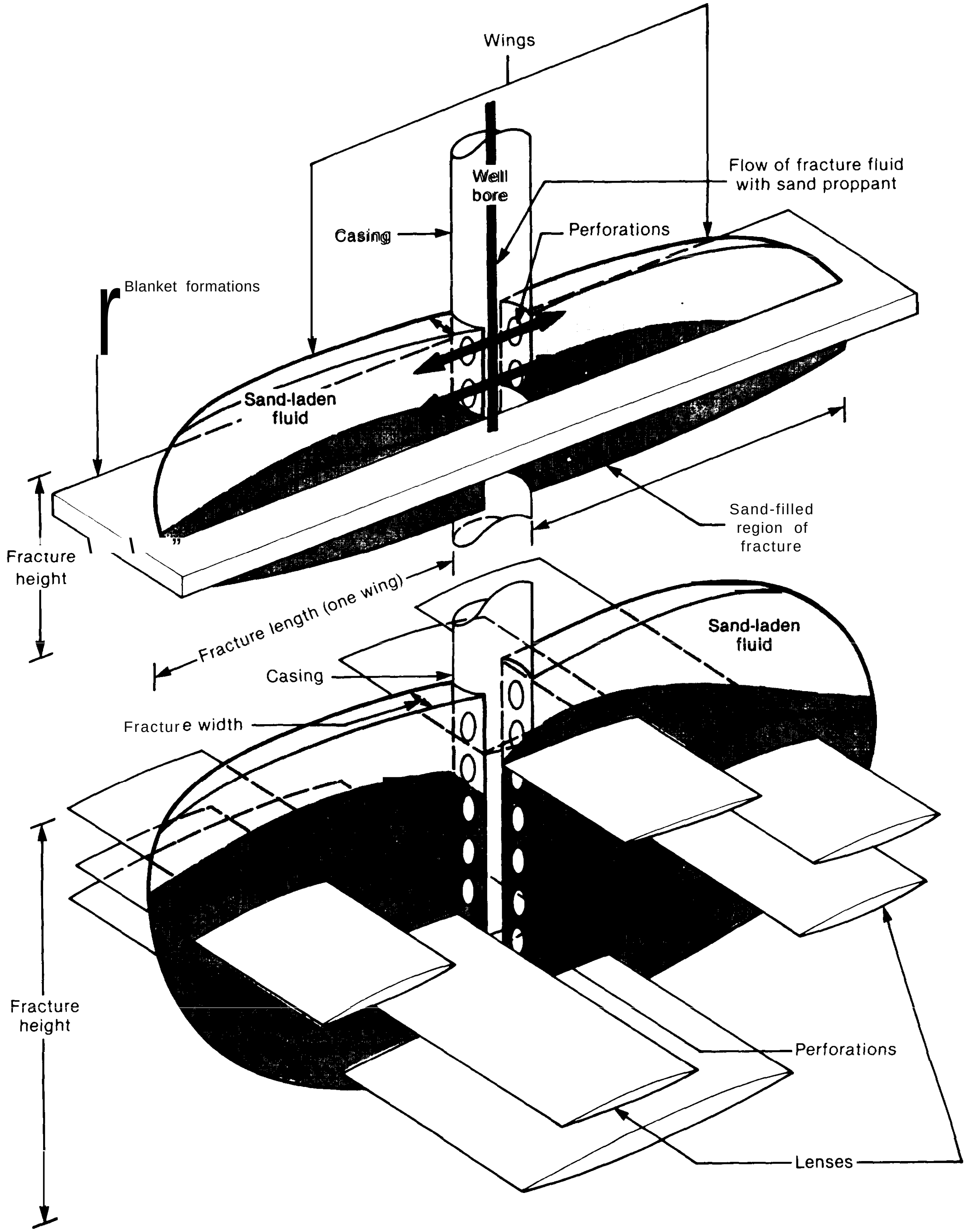
**Table 37.—Conventional and Tight Gas Wells Compared**

| Type well | Perm. (red.) | Fracture length (ft) | Ultimate production (MMCF) | Production life (years) | Wells per section to produce (all gas) | Reservoir area Exposed by fracture (sq. ft) |
|---|---|---|---|---|---|---|
| Conventional . . . . . . . . . . . . . . . | 10 | 100 | 31,700 | 15 | 0.5 | 34,000 |
| Tight—unfractured . . . . . . . . . . | 0.001 | 100 | 390 | 30 | 29 | 34,000 |
| Tight—present technology ., . | 0.001 | 1,000 | 1,838 | *30* | *6* | *340,000* |
| Tight—advanced technology . | 0.001 | 4,000 | 6,015 | 30 | 2 | 1,360,000 |

NOTES Net pay = 85 ft.
Initial pressure = 5,500 psi
Maximum recovery, gas/section =16 BCF for conventional,
11 BCF for tight gas wells.

SOURCE: R. W. Veatch, Jr and O Baker, "How Technology and Price Affect U S Tight Gas Potential, " *Petroleum Engineer International, January 1983.*

**Figure 30.—Conceptual Fractures Created by Massive Hydraulic Fracturing in Blanket and Lenticular Formations**




SOURCE: National Petroleum Council, *Unconventional Gas Sources Tight Gas Reservoirs, Part /,* December 1980

Third, aside from the difficulty of **forecasting** what a fracture will do, it is hard to tell in any detail what a fracture **has done** even after it has been completed and the well is producing (or has proved to be unproductive). In addition, as with any new and rapidly developing technology, state-of-the-art techniques are not necessarily standard practice in commercial ventures. For these reasons, our extensive experience in fracturing has not been as much benefit in projecting future performance as might have been expected.

Despite these difficulties, however, well service companies and producers have been responding vigorously to the various problems encountered in tight formations and have developed a number of variations to the standard fracture treatments. Of particular importance are the development of new fracture fluids and proppants which can increase fracturing efficiency and fracture conductivity. In addition, improved techniques for fracture containment (i. e., keeping the fracture within the gas-bearing layer), fracture prediction, and onsite monitoring will result in more accurate production estimates, greatly reducing the risk of developing these high-cost resources.

Proppants.–Development of new proppants is an important area of innovation by the service companies in response to a need for material that will not crush at high pressures and is light enough for the fluid to transport to the end of the fracture. Recent developments include ceramic beads and resin-coated sands that have lower densities than bauxite–the material currently used in high pressure situations—and thus can be more efficiently transported by the fluid. They appear to have sufficient strength for most fracture applications.

**Fracturing Fluids.–The need** for a fracture fluid that simultaneously can avoid formation damage (clay swelling, etc.) and maintain a high capacity to carry proppants in suspension into the fracture has led to the development of very sophisticated fluids. A particularly significant development is "cross-l inking,' which temporarily increases the viscosity of the fluid—and thus its fracturing and proppant-carrying capability–by linking together polymer chains. After emplacement of the proppant, this viscous fluid alters to a low-viscosity fluid so that it can flow back to the wellbore, minimizing formation damage.

**Fracture Containment.–A common problem** in thin blanket sands is the difficulty of keeping the fracture within the blanket, or pay zone, so that it does not waste its energy fracturing nonproductive rock or actually cause reserves to be lost by fracturing into a water zone or fracturing the reservoir "cap." In general, readily available techniques have not been successful at containing fractures within the pay zone. New techniques have been proposed (including careful placement of the fracture initiation point, very careful control of the fracturing fluid viscosity and pressure, and use of floating proppants to seal off upper non producing portions of the fracture) and are being tested, as discussed in app. B.

**Fracture Prediction. -Understanding** the mechanisms of fracturing and thus being able to predict fracture behavior is critical to reducing the economic risk of tight sands development to manageable levels. The state of the art of fracture prediction, however, comes from sophisticated mathematical models and laboratory experiments with very little field verification.

Current practice in the field is to use relatively simple analytical models against which to compare fracture behavior, proppant placement, fracture length, and well performance. These simple models will often be inadequate in complex tight gas situations, but the more sophisticated models currently available are expensive, time-consuming, and dependent on input data that often are not readily obtained. And, although laboratory experiments allow interesting possibilities for tightly controlled conditions and parametric analysis, it is difficult to be confident that field-scale fractures will behave in the same manner as the small-scale laboratory fractures.

Field-scale testing, using experimental wells or excavating a created fracture, can overcome some of these problems but is extremely expensive. Only a few field-scale tests have been completed and ongoing projects have been curtailed due to Federal funding cuts. Nevertheless, they are providing valuable information on actual fracture configuration.

The difficulties of fracture prediction are particularly acute in the early stages of field development, when theoretical models and analogy with other fields provide the only forecasting guides, Continued development of the field provides data for performance matching of prospective sites with producing wells, and the percentage of successful well stimulations should increase with experience, As discussed below, however, this learning process may be disrupted by problems associated with monitoring fracturing success and interpreting well performance.

**Monitoring Fracture Behavior.–The ability to monitor fracture behavior is critical to tight sands development** for two reasons. First, it is the means by which the existing experience in fracturing can be translated into an ability to predict fracture behavior for new wells. The **inability to measure what** has actually occurred underground in past fracture treatment is responsible for our poor predictive capability. Second, it is critical to field development, because knowing fracture location is necessary in planning additional wells so as to minimize interference between wells. Most of the technologies under development to monitor fractures in the field are adaptations of existing geophysical and well logging techniques, They are discussed in greater detail in appendix B. Some success has been realized in determining fracture height adjacent to the borehole, and in some cases, total fracture length and propagation direction. Problems still exist in determining propped length of the fracture and vertical growth[22] at a distance from the wellbore.

Most of these technologies are still experimental and costly, and are difficult to use. However, fracture diagnostics has received major attention from service companies in the past few years, and innovation has been rapid. improvement and widespread commercial use of these monitoring techniques would have a major effect in lowering the economic risk of tight sands development.

[22]Vertical growth is an important parameter because of the desirability of keeping the fracture within the pay interval. See *Fracture Containment* above.

**Current Fracturing** Success.—In tight gas formations, improved fracturing technologies, developed in blanket sands, have for the most part realized considerable success. Increased fracture lengths in blanket formations often appear to be attainable simply by increasing the volume of fluid and proppant pumped. Fractures over 2,000 ft long have been reported.[23] Where design lengths have not been achieved, failure can generally be attributed to fracturing out of the pay interval, inadequate proppant transport, or extensive formation damage.

An additional but less obvious major problem may still exist in blanket formations. Because massive hydraulic fracturing in low-permeability formations is still a relatively new technology, there are no data on whether the permeability of the fractures can be maintained through time. There is concern that the fractures may close or become plugged before the 30-year production histories are complete. Counteractive measures, such as periodic cleanup treatments or multiple small fracture treatments over the life of the wells, have not been evaluated in terms of their costs, risks, and effect on well performance.

The overall success rate of massive hydraulic fracturing in tight formations is likely to improve to the extent that new technologies are developed to counteract problems such as formation damage and inadequate proppant transport. A certain number of reservoirs, however, may never be amenable to production using massive hydraulic fracturing. For example, adequate fracture containment in some reservoirs may never be possible due to the intrinsic characteristics of the rock. If reservoir boundary layers are substantially weaker than the reservoir rock, the fracture will grow vertically at the expense of horizontal growth. In effect, much of the fluid and proppant is being used to create a fracture in a nonproductive interval. Recovery from such reservoirs cannot be based on the creation of 1,000-ft fractures. More work needs to be done in identifying such formations and determining the optimal fracture treatment to maximize recovery at minimum cost.

[23]B.A. Matthews, W. K. Miller, and B. W. Schlottman, "Record Massive Hydraulic Fracturing Treatment Pumped In East Texas Cotton Valley Sands," *Oil and Gas Journal,* Oct. 4, 1982, pp. 94-98.

Lenticular reservoirs represent a situation where new technologies have not been effective. The NPC-estimated base technology (1,000-ft fractures) is not yet the acknowledged state of the art, nor is there substantive evidence that fractures will penetrate lenses not actually intersected by the well bore. Where large-scale fracture treatments have been attempted in lenticular formations, results have been disappointing. Commercial flow rates were not attained. Insufficient data were collected both before and after treatment to evaluate why fracture treatments failed,[24]

Currently, most producers have returned to less expensive shorter fractures. In some cases they are drilling wells in areas with thick vertical sequences of lenticular sands and stimulating multiple pay intervals by fracturing each interval with fractures on the order of 100 to **500** ft long,

Although per well stimulation costs are lower in this case, cumulative production per well may be less, since a smaller gas-bearing area is in contact with the well bore. This technique may limit the potential recovery from lenticular formations, particularly in the short term. However, there are some data indicating that, over the long term, gas flow from wells in lenticular reservoirs, with relatively short fractures, may not exhibit the expected production decline rates of a limited reservoir.[25] Because the nature of natural fracture systems and gas flow behavior in lenticular formations is not well understood, it may be premature to draw conclusions about the long-term gas recovery of alternative fracturing strategies in these formations.

## Reservoir Characterization Technologies

Techniques and instrumentation to quantify more accurately the physical properties of the reservoirs and to help determine their relationship to one another are crucial to designing more efficient stimulations and making accurate estimates of reserves and recovery rates for economic analysis, Accurate reservoir characterization reduces both the costs and risks of field development.

Conventional methods for determining reservoir parameters include: geologic mapping of exposed areas of the reservoir formation, laboratory analysis of core samples and detailed subsurface correlation of reservoirs, well logging, and well tests. Considerable data have been collected using each of these techniques. Problems with the techniques themselves have been identified. Only limited progress has been made to date in modifying existing techniques and developing new techniques to overcome their problems.

**Laboratory analysis of core samples** recovered from a well provides the best estimate of reservoir properties at that particular site. The data can be correlated with information from other wells to derive a broader regional picture of the subsurface conditions. Date from laboratory analyses can also aid in the interpretation of well logs.

Most samples for laboratory analysis are recovered using conventional coring techniques, The depth of recovery is known, and temperature and pressure information often is available. The recovered samples are subjected to a range of laboratory tests to determine porosity, pore volume, permeability, water saturation, mechanical rock properties, and mineralogy.[26] Electrical and gamma-ray logs are also run on the samples for correlation with well logs.

Because small changes in reservoir properties can substantially alter estimates of the recoverable gas, the laboratory measurements need to give an accurate picture of actual reservoir conditions. Alteration of the physical properties of the rock during its collection represents an important problem for tight formations, contributing to inaccuracies in measurements of permeability, water saturation and other parameters.[27]

[24] An alternative explanation of the production failure (instead of failure of the fractures to reach design lengths) is that the fractures may have achieved design lengths but that other problems, such as water infiltration, and production problems caused by backflow of the sand proppant, were primarily responsible for the disappointing gas flows. The originator of this explanation concurs, however, that the "wells have not been tested and studied sufficiently to decide if the fractures are successful or not." Ovid Baker, Mobil Research & Development Corp., personal communication, 1984.

[25] D.H. Stright, Jr., and J. 1. Gordon, "Decline Curve Analysis in Fractured Low Permeability Gas Wells in the Piceance Basin, " *SPE/DOE Symposium on Low Permeability Gas Reservoirs,* SPE/DOE 11640, 1983, pp. 351-356.

[26] A. R. Sattler, "The Multiwell Experiment Core Program, " *SPE/DOE Symposium on Low Permeability Gas Reservoirs,* SPE/DOE 11763, 1983, pp. 437-442.

[27] National petroleum Council, *Unconventional/Gas sources: Executive Summary,* December 1980.

Techniques for unaltered core recovery exist (e.g., the use of pressurized core barrels), but at present are too expensive and too unreliable for routine use. The available techniques are most practical for research purposes or possibly for use in the early stages of developing a large field, to assist in planning a development strategy,

**Well logs** are among the more commonly used techniques to determine reservoir properties. They are comparatively inexpensive to use, and results generally can be obtained quickly. Unfortunately, many of the logging techniques used in conventional reservoirs have given inaccurate results in the unconventional formations,[28] partly because some conventional methods of log analysis are not appropriate for low-permeability formations and partly because some analysts are not properly accounting for the low-permeability conditions .29

The complex mineralogic content, including clays and cement, and poorly defined interfaces between producing and nonproducing zones in tight formations distort log responses. Resulting porosity and water saturation measurements may be too low or too high. Often the precision of the tools is not sufficient for these reservoirs; e.g., a small error in porosity measurement can result in a large error in inferred fluid saturation. Failure to distinguish gas-productive from water-productive zones, a common problem,[30] drastically complicates the selection of fracture locations.

A prototype logging tool has recently been developed using nuclear magnetic resonance (NMR) to determine porosity, fluid saturation, pore size distribution, and bulk permeability of a formation. Laboratory tests of the tool have been successful; however, the time required to obtain accurate measurements (on the order of several days) is likely to severely restrict its commercial application.[31] NMR logs may end up being most useful on experimental wells where they would be used to gather baseline data for extrapolation. In the long term, it may be a less expensive technology for obtaining reservoir data than coring.

Another approach to improved logging is to use available equipment with specialized interpretive techniques to account for the log distortions associated with the tight formations. An example of new interpretive techniques is a system called "TITEGAS," which is based on equations which define the response of conventional logging tools.[32] The system deals primarily with data from density, neutron, and resistivity logs and makes a number of claims to accurately measure, among other parameters, porosity, gas saturation, clay content, and the presence of natural fractures in complex, tight formations.

Improved interpretation of conventional logs clearly is an important element of better reservoir characterization for tight formations. The need for new interpretive techniques is not clear, however. OTA found some in the research community who felt that, with available techniques, it was now possible to accurately measure reservoir characteristics in most tight gas situations; they blamed current problems on the failure of most practitioners to assimilate the latest advances.[33] There are many others who conclude that logging of tight formations is still error-prone and basically unreliable.

**Well tests** are also frequently used to empirically determine breakdown pressures (e.g., the pressure required to initially fracture a formation) and gas flow rates. From these data, such reservoir properties as in-situ stress and gas permeability can be inferred. Creation of small-scale fractures is particularly useful in determining the difference in the stress characteristics of the rock in the producing and non producing intervals, which in turn allows prediction of fracture containment.

[28] G. C. Kukal, et al., "Critical Problems Hindering Accurate Log Interpretation of Tight Gas Sand Reservoirs," *SPE/DOE Symposium on Low Permeability Gas Reservoirs,* SPE/DOE 11620, 1983.
[29] S. A. Holditch, Texas A&M University, personal communication, 1984.
[30] National petroleum Council, *Unconventional Gas Sources: Executive Summary,* December 1980.
[31] K. H. Frohne, Morgantown Energy Research Center, personal communication, 1984.

[32] G. C. Kukal, "A Systematic Approach for the Effective Log Analysis of Tight Gas Sands," 1984 *SPE/DOE/GRI Unconventional Gas Recovery Symposium,* SPE/DOE/GRI 12851, Pittsburgh, PA, May 13-15, 1984.
[33] S. A. Ho[ditch, Texas A&M University, personal communication, 1984.

Pressure-transient testing is the most common technique used to get a rough estimate of gas permeability prior to stimulation. These tests consist of producing or shutting in the well for a specified period of time and measuring the pressure drawdown or buildup. In low-permeability reservoirs, however, this technique does not always produce useful results, especially during the short time periods feasible for shutting in the well.

## Exploration Technologies

No new technologies have been developed specifically for exploration for unconventional resources, and they are not perceived to be a high priority need because considerable resources have been identified by past drilling efforts. Some existing state-of-the-art technologies used in conventional hydrocarbon exploration are applicable to the unconventional resources. These include aerial and satellite imagery and geophysical surveying.

In tight sands, mapping of surface features from aerial and satellite imagery has proved useful in determining dominant structural trends.[34] Such data may be useful in locating wells so that they make the best use of existing fracture systems.

In tight sands, there may be some potential for using seismic data to delineate the character of beds in a formation.[35,36] If clusters of sand-rich lenses and their orientation could be identified, these data in conjunction with data on regional stress patterns would determine the best location for a well. Three-dimensional, vertical, and cross borehole seismic surveys are being tested at the DOE multi-well site to delineate lenticular bodies and fracture zones in the lenticular formation.[37] Initial results have been disappointing; the data are not of sufficiently fine a scale to map the spatial relationship of the lenses. Detailed geophysical surveys are not likely to be used commercially in the near future due to high costs and complex time-consuming data reduction.

## New Technologies and the Industry

It appears that both tight gas producers and well service companies are willing to experiment with new stimulation techniques. This may have contributed to the rapid development of sophisticated fracturing fluids and proppants.

In contrast, state-of-the-art diagnostic techniques both for reservoir characterization and for predicting and monitoring fracture behavior are not commonly in use among producers. The primary problem appears to be that these techniques are costly and time-consuming. For small and midsize producers in particular, with limited acreage, there is little cost benefit to developing information leading to improved stimulation if they will only be drilling and fracturing a few wells. Larger producers are more likely to make this investment.[38]

The diagnostic techniques may ultimately be the most important factor in making tight gas an economically viable resource. However, because of the limited interest, the rate of development of these technologies is likely to be slow, particularly in the transition from proven concept to commercial product. For these reasons, the industry may continue to be dependent for some time on external research efforts, such as those supported by the Department of Energy and the Gas Research Institute, to develop the tight gas resource.

[34] J. A. Clark, "The Prediction of Hydraulic Fracture Azimuth Through Geological Core and Analytical Stud ies, " *SPE/DOE Symposium on Low Permeability Gas Reservoirs,* SPE/DOE 11611 pp. 101-111.

[35] T. L. Dobecki, "Application of Areal Seismics to Mapping Sandstone Channels, " *Low Permeability Gas Reservoir Symposium,* SPE/DOE 9847, 1981, pp. 205-209.

[36] C. A. Searls, M. W. Lee, J. J. Miller, J. W. Al bright, J. Fried, and J. K. Applegate, "A Coordinated Seismic Study of the Multiwell Experiment Site," *SPE/DOE Symposium on Low Permeability Gas Reservoirs,* SPE/DOE 11613, pp. 115-117

[37] Ibid.

[38] J. W. Crafton, "Fracturing Technologies for Gas Recovery From Tight Sands, " contractor report to OTA, September 1983.

# THE RECOVERABLE RESOURCE BASE AND PRODUCTION POTENTIAL

Estimates of economically recoverable gas from tight gas formations are extremely sensitive to assumptions made about price, level of technology, and the volume of gas-in-place. Existing estimates range from a conservative 30 TCF to almost 600 TCF.

Some recoverable gas estimates include an assessment of the technically recoverable gas (also called maximum recoverable gas) in addition to the economically recoverable gas. Technically recoverable gas represents that gas recoverable from tight formations under optimistic assumptions of technological development, assuming price is relatively unconstrained. The eco**nomically** recoverable gas, in contrast, is subject to both economic and technological constraints. It is usually calculated for several price and technology levels and reflects the sensitivity of recoverability to these parameters.

Detailed estimates of both technically and economically recoverable tight gas were made by Lewin Associates and by the National Petroleum Council in conjunction with their gas-in-place resource estimates. The Gas Research Institute (G RI) has also estimated the economically recoverable resource in tight formations. The NPC study is the most comprehensive of these analyses and is discussed here in the most detail. The other studies are included for comparison, particularly where different methodologies or assumptions are shown to substantially affect estimates. All these estimates assume two levels of technology. The "base case" uses technologies currently available or thought to be available in the near future. The "advanced case" represents technologies that might be developed given a concerted research effort.

## Methodologies and Results

### Lewin Estimate

The Lewin report calculated the technically recoverable gas using its "advanced case" technology criteria, which assume a maximum well spacing of six wells per section (107-acre spacing) and a maximum fracture length of 1,500 ft. They determined that 211 TCF, close to half of the total gas-in-place resource, was technically recoverable. The percent of gas-in-place estimated to be recoverable for the individual basins ranges from 10 to 80 percent, as shown in table 38.

**Table 38.—Maximum Recoverable Tight Gas Resources, TCF**

| | Lewin | | | NPC | | |
|---|---|---|---|---|---|---|
| Appraised basins | GIP[a] | Maximum recovery | Percent recovery | GIP[a] | Maximum recovery | Percent recovery |
| Northern Great Plains/Williston | 74 | 35 | 47% | 148 | 100 | 68 "/0 |
| Greater Green River | 91 | 36 | 40 | 136 | 87 | 61 |
| Uinta | 50 | 18 | 36 | 20 | 15 | 75 |
| Piceance | 36 | 12 | 33 | 49 | 33 | 67 |
| Wind River | 3 | | 33 | 34 | 23 | 68 |
| Big Horn | 24 | 8 | 33 | | | |
| Douglas Creek | 3 | 0.3 | 10 | | | |
| Denver | 19 | 13 | 68 | 13 | 8 | 62 |
| San Juan | 15 | 12 | 80 | 3 | 2 | 67 |
| Ozona | | | | 1 | 0.6 | 60 |
| Sonora | 24 | 16 | 67 | 4 | 2 | 50 |
| Edwards Lime | | | | 14 | 9 | 64 |
| Cotton Valley "sweet" | 67 | 50 | 75 | 22 | 13 | 59 |
| Cotton Valley "sour" | 14 | 10 | 71 | | | |
| Ouachita | 5 | 1 | 20 | | | |
| Total | 423 | 212 | 500/0 | 444 | 292 | 66% |
| Extrapolated basins | | | | 480 | 315 | 66 |

aGIP = Gas-in-place.

Lewin determined that 70 to 108 TCF could be economically produced under **base case technology** conditions for well head prices ranging from $1.75 to $4.50/MCF (1977$) and $2.75 to $7/MCF (1983$), They determined that 150 to 188 TCF could be produced under **advanced case** technology conditions and the same price range, as shown in table 39. The different assumptions used for the base and advanced case estimates are given in table 40.

**Table 39.- Economically Recoverable Gas at Two Technology Levels (TCF)**

| | Price per MCF | | | | | |
|---|---|---|---|---|---|---|
| | Study date dollars | 1983 dollars | Base technology | | Advanced technology | |
| Lewin (1977) . . . . . | 1.75 | (2.75) | 70 | | 149 | |
| | 3.00 | (4.70) | 100 | | 182 | |
| | 4.50 | (7.00) | 108 | | 188 | |
| GRI (1979). . . . . . . | 3.12 | (4.20) | 30 | | 100 | |
| | 4.50 | (6.00) | 45 | | 120 | |
| | 6.00 | (8.00) | 60 | | 150 | |
| | | | Total | Appraised | Total | Appraised |
| NPC (1979) . . . . . . | 2.50 | (3.35) | 192 | 97 | 331 | 142 |
| | 5.00 | (6.70) | 365 | 165 | 503 | 231 |
| | 9.00 | (12.00) | 404 | 189 | 575 | 271 |

**Table 40.—Lewin & Associates Base v. Advanced Technology**

| Parameter | Base case | Advanced case |
|---|---|---|
| Fracture height , . . . . . . . . . . . . | 4 times net pay (200' minimum, 600 maximum fracture height) | 3 times net pay (150' minimum, 400 maximum fracture height) |
| Fracture length (one way) | | |
| Shallow gas sands . . . . . . . . | 200 ' | 500 ' |
| Near-tight sands . . . . . . . . . . | 500' | 500 ' |
| Tight gas sands. . . . . . . . . . . | 1,000 ' | 1 ,500' |
| Fracture conductivity . . . . . . . . | Decreases with depth using current proppants and methods | (Using improved proppants and methods to maintain adequate conductivity) |
| Field development | | |
| Lenticular . . . . . . . . . . . . . . . . | *320* acres per well (2 wells per section) | 107 acres per well (6 wells per section) |
| Blanket . . . . . . . . . . . . . . . . . . | 160 acres per well (4 wells per section) | 160 acres per well (4 wells per section) |
| Net pay contacted | | |
| Lenticular sands | | |
| 320 acres drainage . . . . . . | 17% | — |
| 107 acres drainage . . . . . . | — | 800/0 |
| Blanket sands . . . . . . . . . . . . | 100% | 100% |
| Dry hole rate: | | |
| Lenticular ., . . . . . . . . . . . . . . | *300/0* | 200/0 |
| Blanket . . . . . . . . . . . . . . . . . . | *20%* | 10% |
| Discount rate. . . . . . . . . . . . . . . | *26°/0 (20°/0* real) | 16°/0 (10°/0 real) |

SOURCE: V. A. Kuuskraa, et al., *Enhanced Recovery of Unconventional Gas: The Program- Volume II,* U.S. Department of Energy report HCP/T2705-02, October 1978.

The Lewin estimates were developed using reservoir simulation-based production curves for blanket and lenticular reservoirs to determine cumulative reserves from a well over a 30-year period. Input parameters included reservoir characteristics for the individual basins and pay quality intervals, fracture lengths, fracture conductivity, and drainage area of a well.

Production per year per well for the assumed wells, multiplied by the assumed gas price, gives the positive cash flow for the economic model. Offsetting costs include the initial investment in exploration, drilling, and stimulation, plus operating and maintenance costs, royalties, and taxes. A required rate of return of 20 percent (real) was used for the base case estimates, dropping to 10 percent in the advanced case to reflect lower risks associated with the greater predictive capabilities and higher efficiencies associated with advanced technology,

### National Petroleum Council

In contrast to the Lewin method of calculating the technically recoverable gas using its advanced technology criteria, the NPC determined the maximum recoverable gas directly from the gas-in-place estimates. The maximum recoverable gas is defined as the total amount of gas that can be produced from a reservoir before the gas pressure in the reservoir reaches the "well bore drawdown pressure."[39] This quantity is further modified by a "recovery adjustment factor" meant to take into account the existence of very low permeability areas within a field that are unlikely to be productive, Recovery adjustment factors range from 50 percent for blanket reservoirs with average permeabilities of 0.00001 md, to 95 percent for blanket reservoirs with average permeabilities of 0.3 md.[40] Lenticular reservoirs use more conservative adjustment factors. The NPC study determined the technically recoverable gas for a set of appraised and extrapolated basins to be 292 and 315 TCF respectively. Its results are also shown in table 38.

The NPC estimates of economically recoverable gas range from 192 TCF at $2.50/MCF (1979$) with **base case** technology to 575 TCF at $9/MCF with **advanced technology,** as shown in table 39. The base case is represented as "current fracturing technology and well spacing regulations, " but apparently allows for some evolution and improvement of the technologies over time as operators gain experience. The advanced case incorporates new technologies developed by a concerted R&D program. The methodology used by the NPC to determine the economically recoverable gas is similar to the Lewin methodology. Cumulative production per well was determined from type curves[41] for base and advanced technologies. This gives the number of wells per section required to produce all of the recoverable gas in a given permeability level in a formation. The base and advanced technology criteria are shown in table 41. In the economic model, costs of drilling and fracturing and operating costs are subtracted from income from production at various prices, and a marginal rate of return is calculated. All formations with a rate of return less than a prescribed value (10, 15, or 20 percent) are considered unprofitable.

It has been suggested that the NPC method of using type curves designed for 640-acre (one well per section) spacing to determine cumulative production levels from blanket formations at 160-acre (four wells per section) and smaller spacings could result in a substantial overestimate of the recoverable resource. The expected cause of this overestimate is the inability of the (640-acre) type curve to account for the greater interference between wells that would occur at 160-acre spacing (interference reduces the production per

[39] The production of gas depends on a pressure gradient existing between the wellbore and the rest of the reservoir. As the pressure in a formation is reduced through production, the reservoir pressure and the wellbore pressure approach equilibrium. Eventually no further gas will flow naturally, The NPC assumed that the reservoir pressure at this point would be approximately 10 percent of the original formation pressure. Any gas remaining in the reservoir cannot be produced except by expending energy to induce an artificial pressure gradient.

[40] NPC Report, vol. V, part 1, table 15.

[41] Type curves are normalized representations of cumulative production over time generated from reservoir simulation models. Because the data are generated in terms of dimensionless values, they are applicable over a wide range in the reservoir parameters (permeabilities, porosities, net pay, pressure, temperature, gas composition, and fracture conductivity). Different type curves, however, are required for different well spacing rules. They are an efficient technique for obtaining estimates of cumulative recovery and producing rates for a large number of reservoirs.

**Table 41.-NPC Base v. Advanced Technology**

| | Blanket formations | | Lenticular formations | |
|---|---|---|---|---|
| 1. Fracture height | 4 times net pay | 3 times net pay | 6 times net pay | 4 times net pay |
| Range (ft) | 200-600 | 150-400 | 300-1,000 | 200-600 |
| 2. Fracture conductivity (md-ft) | 500 | 1,000 | 500 | 1,000 |
| 3. Fracture length, wellbore to tip (ft), permeability >=0.1 md | | | | |
| Effectively achieved | 1,000[a] | 2,000[a] | 1,000[a] | 4,000[a] |
| Hydraulic design required | 1,700[a] | 2,500[a] | 1,700[a] | 5,000[a] |
| 4. Field development, wells per section (maximum) | 4 | 12 | 4 | 12 |
| Acres per well (minimum) | 160 | 53 | 160 | 53 |
| 5. Lenses remote from the wellbore may be contacted by fractures? | NA | NA | Yes | Yes |

aProduct of fracture permeability and fracture width.

SOURCE: National Petroleum Council, Unconventional Gas Sources, vol. V, part 1, December 1980.

well).[42] The overestimate of production per well would be greatest at the higher permeability levels where more of the economically producible gas is found. This problem is not as serious as it might appear, however, because of the way the type curve data were used in the NPC report. If the NPC had computed total production from wells drilled to determine gas recovery, assuming a standard "four wells per productive section," then they would have overestimated the maximum recoverable resource. Instead, as noted previously, NPC determined the maximum recoverable gas independently of the type curves, applying recovery factors to the gas-in-place. The cumulative 30-year production of a well, derived from the type curves, was used only to determine the number of wells per section required to produce the maximum recoverable gas.

At the higher permeability levels, all of the recoverable gas can be produced by less than the four wells per section base case constraint. Thus, although the NPC may have *underestimated the number of wells* required to produce these permeability levels, unless the actual number of wells required exceeds the four wells per section constraint, *it has not overestimated the amount of gas* that can be produced.

At lower permeabilities (0.3 md and lower), where more than four wells per section are required to produce all the gas in the formation, the NPC technique may overestimate the economically recoverable gas for the base case. Nevertheless, the amount of gas involved is not large. For example, a sensitivity analysis of the NPC estimates shows that a shift to 160-acre type curves would not have changed the estimate of recoverable reserves for the blanket formations by more than 10 percent.[43] A similar problem does not exist for the advanced case because all of the gas at all permeability levels can be produced from less than the allowed 12 wells per section.

## Gas Research Institute

The most recent estimate of the gas recoverable at different price and technology levels has been made by the Gas Research Institute and is also shown in table 39. These estimates are considerably lower than both the Lewin and the NPC estimates, ranging from 30 TCF at $3/MCF (1979$) and base technology, to 150 TCF at $6/MCF and advanced technology. GRI derived its estimate by making judgmental adjustments to existing estimates. It concentrated on those basins where

[42] Gruy petroleum Technology Inc. report to EIA, "Correlations for Projecting Production From Tight Gas Reservoirs."

[43] J P. Brashear, et al., "Tight Gas Resource and Technology Appraisal: Sensitivity Analysis of the National Petroleum Council Estimates, 1984 *SPE/DOE/GRI Unconventional Gas Recovery Symposium,* SPE/DOE/GRI 12862, Pittsburgh, PA, May 13-15, 1984.

the tight sands resource was best understood and, in addition, attempted to eliminate tight gas that might conceivably be considered conventional. Its conservative approach was specifically designed to provide an estimate of that portion of the tight gas resource which had a high probability of occurrence.

## Comparison of Estimates and Discussion of Uncertainties

One of the major differences between the recoverable resource estimates is the difference in the total areas assessed, since the amount of gas estimated to be recoverable is intimately tied to the proportion of the gas-in-place actually included in the study and evaluated for recoverability. The NPC, Lewin, and GRI recoverable resource estimates each are based, implicitly or explicitly, on a different gas-in-place resource base. The NPC, by including both the appraised and extrapolated basins, begins with the largest gas-in-place resource base. Lewin restricts its estimate to those basins for which considerable information is available. GRI also restricts its estimate on this basis, but apparently further limits the resource base it evaluates by excluding all potential areas of overlap with conventional resource estimates. Where the areas assessed by NPC, Lewin, and GRI overlap, however, there are still substantial differences in the estimates of recoverable gas. These differences result from the underlying assumptions used in the estimating process.

In the sections that follow, we first compare recovery estimates for a comparable area—the appraised resource—to show how different assumptions affect the estimates of technical y and economically recoverable gas. Next, we briefly discuss a portion of the resource base evaluated by broad geologic analogy rather than direct appraisal—the extrapolated resource. Finally, we discuss briefly the geological/geographical boundaries used in the resource estimates. Included in each section is a discussion of the major uncertainties underlying the estimates and how these uncertainties affect the amount of gas recoverable. it is important to remember that many of the uncertainties in calculating the gas-in-place are propagated through to the calculations of the technically and economically recoverable resource.

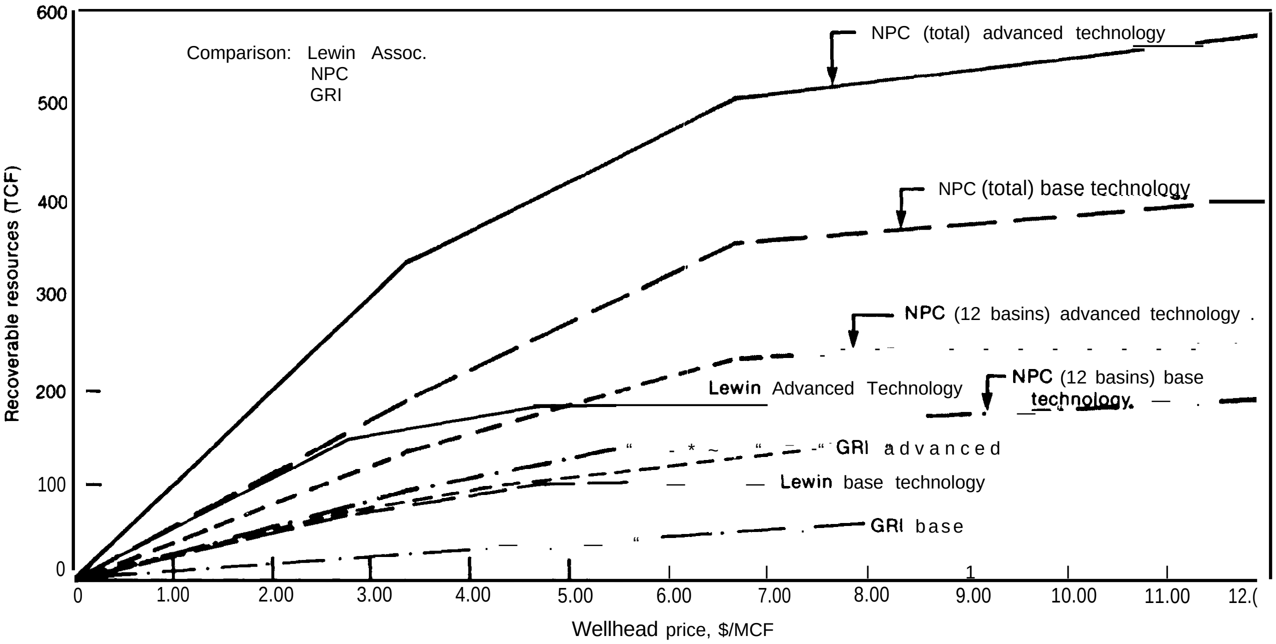
### The Appraised Basins

The appraised basins of the Lewin and NPC studies have comparable total volumes of gas-in-place, as discussed in the previous chapter. Despite this agreement, their estimates for potential recovery of tight gas are significantly different (the technically recoverable gas is two-thirds of the gas-in-place in the NPC study compared to half of the gas-in-place in the Lewin study). Differences in percent of gas-in-place recoverable are particularly apparent on an individual basin level, as seen in table 38, and can be attributed to the different assumptions used by the estimators to calculate both technically and economically recoverable gas.

The NPC approach to estimating **maximum recoverable gas is independent of any technology assumptions and effectively assumes that virtually all gas in a formation** will ultimately be in contact with a well bore. In contrast, the Lewin estimate is constrained by a set of advanced technology criteria that do not allow the entire gas-bearing portion of a formation to be contacted, even under the most favorable conditions. The Lewin estimate is more conservative than the NPC estimate in its assumed fracture lengths and, for lenticular resources, in its assumptions about the probability of producing from lenses not in direct contact with the wellbore.

Differences between the Lewin and NPC estimates of **economically recoverable** gas in the appraised basins are caused primarily by differences in their assumptions about base and advanced case technology conditions (tables 40 and 41). For the base technology case, the Lewin estimates of economically recoverable gas are only two-thirds of the NPC estimates (see fig. 31). The effects of shorter assumed fracture lengths in some areas, especially the Northern Great Plains, a constraint of two wells per section in lenticular formations, and the constraint that only lenses in direct contact with the wellbore could be produced probably account for the lower estimates of recoverable gas in the Lewin estimate.

**Figure 31.—Comparison of Recoverable Estimates (for gas price in** 1983$)




Under advanced technology criteria, there is little difference between the NPC and Lewin estimates at the lower prices despite the NPC technical potential for much higher levels of production using 2,000- to 4,000-ft fractures and up to 12 wells per section. The increased "per section" production potential in the NPC analysis is probably offset by increased costs of longer fractures, which would make many of the lower permeability prospects unprofitable at lower prices. The lower marginal rate of return in the Lewin advanced case allows it to bring a number of its previously unprofitable wells on line, increasing the percent of the technically recoverable gas that can be economically produced. In this case, tradeoffs between costs, rates of return, and recovery per well allow two entirely different sets of assumptions to result in approximately the same amount of gas produced. At higher prices, however, the higher fracturing costs of the NPC estimate become less of a factor in determining profitability of a well and the NPC estimate of recoverable gas is again higher than the Lewin estimate.

The above comparison of the Lewin and NPC appraised basin estimates points out how different assumptions of price, rate of return, and state of tech no logic development affect the estimates of technically and economically recoverable gas. The inherent uncertainty in some of these assumptions is the major factor in whether the estimates can be considered an accurate representation of the recoverable resource.

The primary uncertainty lies in the technology assumptions for the different tight gas formations. The NPC assumptions are considerably more optimistic than those used by Lewin. Assumptions made by the NPC that are most likely to be challenged include:

1. fractures in lenticular formations will contact (and allow production from) lenses distant from the wellbore;
2. currently available technology will allow propped 1,000-ft fractures in all producing situations, advanced technology will allow 4,000-ft fractures with fracture heights less

than currently achieved with 1,000-ft fractures; and

3. every stimulation will be successful in achieving its design criteria (length, orientation, and direction).

OTA considers these assumptions to be optimistic, especially for the base case, but also for the advanced case as well. As noted in the technology discussion, not all of the base case conditions have been met at the present time. Although evolution and improvement of existing technology during normal operations[44] will occur, the base case criteria still appear optimistic. Some of the base case and advanced case criteria do appear likely to be met over the long term under a strong R&D program; others may deserve to be substantially modified.

1. **Contacting Remote Lenses.** A major assumption of the NPC study is that massive hydraulic fractures in lenticular formations can contact lenses distant from the wellbore, in both the base and advanced technology cases. This assumption underlies the inclusion of vast areas of lenticular formations into the tight gas recoverable resource base. The NPC estimates that 126 TCF is recoverable from lenticular formations in 4 of the 12 appraised basins—43 percent of the total recoverable resource in all appraised basins. To date, **no** evidence exists that remote lenses can be contacted, despite a number of fractures completed in lenticular formations. In recent analyses of tight gas resources, GRI has assumed zero contact of remote lenses for its "present technology" case.[45] The DOE Multiwell Experiment is designed to answer this remote lens question; if the results of this experiment prove disappointing, estimates of the amount of gas that can be recovered from tight lenticular formations may need to be substantially reduced.

A recent sensitivity analysis of the ability to contact remote lenses has been performed using a computer simulation of the NPC study.[46] This analysis determined that the technically recoverable gas from appraised lenticular formations would be reduced by about half if remote lenses could not be contacted. For example, for an allowable 12 wells per section, recovery per well would drop from 100 to 48 BCF. This effect is magnified for the **economically** recoverable gas, especially at moderate prices, because some lenticular formations cannot be developed at all unless remote lenses can be produced. For example, **at gas** prices of $2.50/MCF in 1979$ ($3.35 in 1983$) and a rate of return of 15 percent, assuming advanced case technology, the NPC-estimated economically recoverable gas from the appraised lenticular basins is 37 TCF if remote lenses can be produced and only 10 TCF if they cannot be. Without production from remote lenses, the lenticular tight formations may not play a significant role in future U.S. gas production.

2. **Achievable fracture characteristics.** As noted earlier, there is considerable disagreement about the extent to which the NPC-defined fracture characteristics realistically reflect both current technology and achievable future technology.

For the NPC "base" or current technology, OTA is particularly skeptical of the assumption of 1,000-ft achievable fractures for the lenticular resource (see the *Technology* section). Recent Gas Research Institute analyses have used propped fracture lengths of 600 ft and fracture conductivities[47] of 400 md-ft (v. NPC's 500 md-ft) to represent "present" technology.[48][49] As with changes in assumptions about contacting remote lenses, the effect of these changes in fracture characteristics is to substantially reduce the recoverable gas at all price levels. Figure 32 shows the combined effect on recoverable resources of the "no contact of remote lenses" assumption and the changes in fracture characteristics. For example, recoverable gas at $9/MCF (1982$) is reduced by about 25 percent, from roughly 400 to 300 TCF.

[44] As noted previously, such evolution and improvement is considered to be included in the base case technology conditions.

[45] Briefing document for the Tight Gas Analysis System, Lewin & Associates, Inc., 1984.

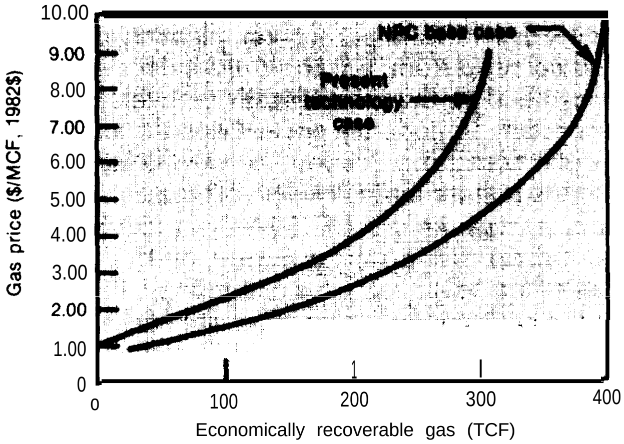
[46] The simulation is called the TGAS Simulator, described in Brashear, et al., op. cit.

[47] Fracture conductivity: the product of fracture permeability and width, a measure of how well gas can flow along the fracture.

[48] Briefing document for the Tight Gas Analysis System, *op. cit.*

[49] GRI's *"present* technology" and NPC's base case may not describe precisely the same technology level, however, because NPC's base case includes the evolutionary effects of future operations. On the other hand, the GRI criteria were defined several years after the NPC's were.

**Figure 32.–Comparison of NPC Study Results With GRI Present Case—Tight Gas Sands Recoverable Gas**




SOURCE: S. Ban and D. Dreyfus, "Adequacy of Gas Supply: The Role of Technology," Natural Gas in Texas Conference, Austin, TX, May 10, 1984. Available from Gas Research Institute.

GRI has also chosen to use more modest fracture characteristics than NPC for its "R&D Success" case, which includes improved geological and geophysical techniques, improved fracture design and diagnostics, and real-time fracture diagnosis and control:[50] fracture length and conductivity are assumed to be 2,000 ft and 800 md-ft, respectively, v. NPC's 4,000 ft and 1,000 md-ft. Although OTA agrees that these NPC "advanced case" fracture characteristics appear to be quite optimistic, our major concern lies with the NPC assumptions for fracture height. GRI has accepted the NPC's fracture height criteria for both the current and advanced cases.[51] According to these criteria, the 4,000-ft fractures will have shorter fracture heights than the 1,000-ft fractures (e.g., for blanket sands, fracture height is six times net pay for the 1,000-ft fracture and four times net pay for the 4,000-ft fracture).

Because of the shorter fracture height, the longer fractures will be cheaper per unit length than the base case fractures, which in turn adds substantially to the estimated recoverable resource in the "advanced technology" case. The fracture height assumption reflects NPC's belief that careful control of fracture placement and fracturing fluid pressure will serve to maintain small fracture heights. This is the opposite of current experience, where longer fractures generally are associated with increased fracture height and higher (per unit length) costs. On the other hand, current fracturing technology does not include reservoir and fracture-propagation modeling capabilities that provide "real time" (during the actual fracturing process) control of well treatmerits.[52] GRI is sponsoring research to develop this capability and clearly hopes that successful development will allow longer fractures to be produced without increasing fracture height. Future improvement in fracture control clearly is a certainty. Nevertheless, assuming a reduction in fracture height in conjunction with a fourfold increase in fracture length appears to be optimistic.

In addition, the NPC's specification of fracture height as a constant multiple of net pay thickness serves to automatically favor thin, higher permeability intervals over thicker, low-permeability intervals, This is because fracturing costs area function of the volume of fracture fluid required, which in turn is a function of fracture height. Consequently, using NPC's assumptions, thin, rich, high-permeability pay intervals will tend to appear very attractive to develop even though in actual experience it may be difficult to achieve very long fractures in such intervals without exceeding the "four or six times net pay" fracture height constraint. As a result, the NPC's fracture height assumptions may yield estimates of more gas at lower prices than maybe realistically producible. However, this effect may be counter balanced somewhat by the empirical relationship between net pay thickness and permeability assumed by NPC. Because the NPC believed that most of the tight gas resource lies in the lower permeability rocks, they assumed that the higher permeability gas-bearing zones would be thin and the lower permeability zones would be thick. Because the initial productivity, and thus the economic viability, of a well depends on the product of thickness and permeability, the assumption that higher permeability zones would essentially always be thin is pessimistic. An alternative

[50] The latter improvement allows problems encountered in fracturing to be diagnosed and fixed in "real time, " i.e., as the fracture is being made.

[51] Briefing document, Op. cit.

[52] Gas Research Institute, Status *Report: GRI's Unconventional Natural* Gas *Subprogram,* December 1983,

assumption, albeit an optimistic one, that all pay zones are the same thickness would yield a 46-percent increase in the recoverable resource at $2.50 gas in 1979$ ($3.35 in 1983$) with the base technology. The relative effect decreases at higher gas prices and improved recovery technology.[53]

Finally, whether or not the NPC's fracturing criteria are **generally** realistic, OTA is concerned that they were universally applied to all formations regardless of geologic character, except for the separation of blanket and lenticular formations. For example, using these fracturing criteria, the Northern Great Plains becomes one of the dominant sources of recoverable gas from blanket formations. Apart from the question of how much gas exists in the Northern Great Plains, geologic characteristics of these shallow, low-pressure reservoirs can also restrict the amount of recoverable gas. For example, the presence of water-sensitive clays makes these reservoirs sensitive to formation damage.[54] Also, experience has shown that fractures in shallow formations may propagate horizontally rather than vertically, reducing the net pay drained by each well, and significantly reducing the recovery efficiency, Thus, the appropriateness of assuming 4,000- or even 1,000-ft fractures in assessing recovery from these reservoirs, and thus counting on up to **70** to 90 percent recovery of the gas-in-place, is questionable. The Lewin study assumed that short fractures (200 to 500 ft) would be used in these reservoirs, and assumed that fractures in the shallower formations would propagate horizontally.[55] Its ultimate recovery efficiency in the Northern Great Plains is only 47 percent of the gas-in-place (table 38). More accurate assessment of the recoverability of gas from these formations, using more site-specific technologies, is needed. For example, the use of air-drilled open hole wells at close spacings may be a preferred method of production considering the low drilling and completion costs for these depths and the avoidance of formation damage.[56] Ultimate recovery from this region appears more likely to be on the order of so percent (or less) of the gas-in-place rather than the NPC's estimated **70** to 90 percent.[57]

3. **Success Rate of Fracture Treatments.** Further, the NPC study assumes that each fracture treatment is successful in achieving design criteria. Fractures are assumed to never grow vertically out of the pay zone at the expense of fracture length. They are never offset against existing natural fractures or intersect one another at close well spacings. Formation damage is minimal. The NPC approach assumes that technologic development will be able to overcome all of these problems. In fact, however, some of these problems appear to be inherent to the formations. With better reservoir characterization, producers may be able to better predict where fractures will grow out of the pay zone or what the probability is that they may intersect, but they may never be able to control many of these occurrences; other occurrences may be controllable but only at added cost. OTA feels that 100 percent fracture success is an overly optimistic assumption.

[n addition to uncertainties associated with the fracturing technology criteria, an important uncertainty in the appraised recoverable resource is associated with the geology of the Northern Great Plains:

## The Northern ‘Great Plains

If gas does not exist in large quantities in the Northern Great Plains, the estimated recoverable resource will have to be substantially reduced regardless of the success of advanced technologies. The NPC estimates that 100 TCF, one-third of the technically recoverable gas in the appraised basin estimate, can be produced from this region.

According to the NPC criteria, much of this gas ought to be relatively inexpensive to produce. Approximately 54 TCF is estimated to be recoverable at $2.50/MCF (1 979$) using base technologies. Even the more conservative Lewin estimates predict that 21 TCF will be recoverable at $1.75 (1977$) under base case conditions. Despite this apparent incentive, however, there appears to be little current interest in developing

[53] J. P. Brashear, et al., op. cit.
[54] R. L. Gautier and D. D. Rice, "Conventional and Low Permeability Reservoirs of Shallow Gas in the Northern Great Plains, " *Journal of Petroleum Technology,* July 1982.
[55] Lewin, vol. II, pp. 3-57.
[56] Gautier and Rice, Op. cit.

[57] Dudley Rice, U.S. Geological Survey, Denver, CO, personal communication.

tight gas in the Northern Great Plains. No FERC filings for tight gas designations in the Northern Great Plains have been made to date. Reasons for the lack of interest may include external constraints, such as an absence of pipelines and market problems due to the existing surplus. However, there are other tight gas basins with similar transportation/market problems—e.g., the Uinta and Piceance basins—that have sustained at least moderate development efforts, so these problems do not fully explain the lack of activity in the Northern Great Plains.

On the other hand, a recent GRI analysis[58] claims that the current lack of activity and high estimated recoverable resource can be reconciled by comparing the profitability of **individual prospects** in the Northern Great Plains with prospects in other tight gas basins. The Northern Great Plains is described as "having a very geologically diffuse resource, which would require large numbers of shallow, low-pressure wells spread over great distances."[59] While the Northern Great Plains contains more total economically recoverable gas than competing basins at any price level, several basins in the Rockies and Southwest were found to contain a number of individual formations offering greater profitability **per thousand cubic feet of gas extracted.** These prospects are characterized as offering larger field sizes and greater well productivity and recoverable gas per section than prospects in the Northern Great Plains. Because developers make investment decisions on the basis of individual prospects and not entire basins, development of the Northern Great Plains might not be expected to occur until the more attractive prospects elsewhere were exploited. GRI also speculated that the intermingling of tight formations with established gasfields in the Rockies and Texas would also provide an important incentive for developing these basins first, because developers tend to want to drill in areas where they have had previous successful experience.

The questions concerning gas-in-place, producibility, and current activity levels call for an independent assessment of the Northern Great Plains production potential. Such an assessment should include a reevaluation of the gas-in-place, the engineering characteristics of the reservoirs, and the costs and technologic requirements of producing from these reservoirs. An analysis of the external constraints and their temporal significance is also needed.

## The Extrapolated Resource

The NPC approximately doubles the volume of its gas-in-place estimate by including 101 additional basins in the resource base. Because it assumes that the formations in the extrapolated basins have similar producing characteristics to analog formations in the appraised basins, it also approximately doubles the estimated technically recoverable resource as well as the economically recoverable resource.

It is generally agreed that the extrapolated basins represent the most speculative part of the NPC resource estimate. In addition to the uncertainty as to the quantity of gas existing in these basins, there are further uncertainties in the extrapolation of engineering characteristics for gas-producing formations and the consequent estimates of production. There is sufficient information in these areas to say that some gas is there, and that some of it may be economically produceable, so the extrapolated resource certainly cannot be entirely disregarded. If FERC filings can be considered indicative of productive areas (if not of actual volumes of gas), then the large number of filings for the Eastern and Southwestern United States may bean encouraging sign for the production potential from extrapolated basins.

Recent studies have been undertaken to better characterize the extrapolated basins,[60] but data sufficient to revise the NPC estimates are not yet available. Because the potential contribution of the extrapolated basins to the recoverable resource has been estimated to be so large, more detailed assessments remain a high-priority area for future research.

[58] J. 1. Rosenberg, "The Economics of Tight Sands Gas Extraction as Affected by R& D," *Gas Research Insights* series, Gas Research Institute, August 1983.

[59] Ibid.

[60] R. J. Finley and P.A. O'Shea, "Geologic and Engineering Analysis of Blanket-Geometry Tight Gas Sandstones, " *1983 SPE/DOE Joint Symposium on Low Permeability Gas Reservoirs,* SPE/DOE 11607.

Many who use the NPC figures in their analysis of gas supply consider only the recoverable gas in the appraised basins because of the speculative nature of the extrapolated resource. OTA suggests that it is overly conservative to disregard the extrapolated resource altogether, especially since FERC filings indicate that development is going forward in some of the extrapolated basins; however, until better estimates are available, it may be more useful to consider the extrapolated recoverable resource estimates in a category separate from the more precise estimates of the appraised basins.

## Effect of Boundary Conditions

**Double Counting.**–The separate estimation of the conventional and unconventional natural gas resource base by different groups, coupled with poorly stated "boundary conditions" for each estimate, can lead to some resources being counted in both conventional and unconventional estimates (e.g., "double counting"). This would lead to an overestimate of the total natural gas resource.

Tight gas has the highest level of current production of all the unconventional resources. Because of the existing production, there is some controversy over how much of the tight gas resource has already been included in conventional resource estimates, and thus in estimates of future conventional gas production. To the extent that it is so included, it cannot be considered as a potential **supplemental** source of supply.

Most conventional resource assessments are not well documented; and comparison of conventional with unconventional estimates is not straightforward. Recently, the Potential Gas Committee (PGC) has attempted to determine what percent of its total conventional undiscovered **recoverable** resource[61] occurs in tight formations. It concludes that 172 TCF, or 20 percent of its total potential recoverable resource, is tight gas.[62]

[61] Including resources made avai [able by the growth of already-discovered fields because of enhanced recovery, discovery of new reservoirs, etc.

[62] The PGC tight gas estimate included both tight sands and Devonian shales. However, conversations with the people responsible for determining tight gas in the eastern region have indicated that the Devonian shale contribution to the tight gas estimate is very small.

A considerable portion of this gas does not overlap with the NPC tight gas resource, however, because it is below 15,000 ft (the NPC depth limit), in areas already undergoing development (and thus not unconventional according to the NPC definition), or simply in locations not considered by the NPC study to be prospective.

There is no unequivocal data set that will allow an accurate estimate of the overlap between conventional and unconventional natural gas resources. Estimates range up to 100 TCF,[63] and the PGC has recently suggested that as much as half of the tight gas in its estimate may represent an overlap with the NPC resource[64] An OTA analysis of the overlap, presented in appendix C, indicates that the total overlap between the PGC-estimated 172 TCF of tight gas and the N PC-estimated 606 TCF of recoverable tight gas may be as low as 30 TCF. Even the low side of the overlap, however, though relatively small compared to the total size and large uncertainties in the tight gas resource estimates, **is still important in assessing the unconventional tight gas contribution to near- and mid-term production** because the 30 TCF are in the most accessible, least expensive portion of the tight gas resource. The main areas of overlap occur in the blanket formations of the Rocky Mountain Basins and the Cotton Valley Trend in Texas and Louisiana. These areas currently are the major producers of gas from tight formations, and the NPC report has predicted these areas to be the main contributors to "unconventional" supply in the next 20 years.

**Deep Tight** Gas.–Another problem arising from inadequately defined boundary conditions is that certain potential resources may be overlooked entirely, resulting in an **underestimate** of the total resource base. For example, the PGC estimated that its conventional gas resource base includes some 89 TCF of gas in tight formations at depths greater than 15,000 ft. The NPC report acknowledges that large volumes of gas probably occur at depths greater than 15,000 ft, but they assumed this gas to be too speculative a resource to in-

[63] Vello Kuuskraa, Lewin & Associates, Inc., personal communication, 1984.

[64] H. C. Kent, Director, Potential Gas Agency, testimony before the Subcommittee on Energy Regulation, Senate Committee on Energy and Natural Resources, Apr. 26, 1984.

elude in its tight gas assessment.[65] Other experts have concurred that large volumes of gas exist in deep tight formations, in the Rocky Mountain Basins as well as the Anadarko and Arkoma Basins in Oklahoma and Arkansas. Many of the deeper Rocky Mountain formations are lenticular.

Apart from the PGC estimate, which is widely viewed as an estimate of the **conventional** resource, there are no quantitative estimates of recoverable resources in deep tight formations. Deep tight formations, other than those already included in the PGC estimates, probably should be included in future estimates of the unconventional tight sands resource at least for the estimates of gas-in-place. They represent no more speculative a source of gas supply than the unfractured portions of the Devonian shales or the deep coal seams, both of which generally are included in gas-in-place estimates of unconventional resources.

## Conclusions About Recoverable Gas

To summarize, OTA considers the NPC estimates of recoverable tight gas resources to be optimistic. The major reasons for this appraisal are:

1. **The Northern Great Plains.** OTA considers it quite plausible that the recoverable resources in the Northern Great Plains are considerably lower than the 100 TCF maximum recoverable gas projected by the NPC.
2. **Gas-in-Place.** Aside from the Northern Great Plains, OTA believes the NPC's gas-in-place estimates to be reasonable, in the context of "most likely" values. The margin for error is large, however, especially for the extrapolated resource; the estimate for the extrapolated resource should be considered as speculative.
3. **Technology.** OTA considers some important aspects of NPC's appraisal of current technology and projection of advanced technology to be over-optimistic. Of particular concern is the assumption that fractures will be able to penetrate and drain lenses remote from the wellbore. Another important concern is that very long fractures (up to 4,000 ft) can be achieved with a net decrease in fracture height.

OTA also believes that **all** available estimates of recoverable tight gas are highly uncertain because of poorly defined reservoir characteristics and technologic uncertainties. However, there seems little doubt that large quantities—at least a few hundred TCF—of tight gas will be recoverable even under relatively pessimistic technologic circumstances, provided gas prices reach moderately high levels in the future (e.g., $5 to $7/MCF in 1984$).

## Annual Production Estimates

Any forecasting of actual production from the tight gas resource requires making a number of assumptions over and above those made to estimate the recoverable resource, and similarly uncertain. Projections must be made of the price of gas and the state of technology development over the time interval of the forecast. These are the critical uncertainties. The amount of "high potential" land immediately available for drilling must be estimated. Finally, an estimate must be made of the number of wells that can be drilled within a single year and the rate of increase in following years. The comparison of different forecasts requires an understanding of these underlying assumptions.

The Lewin study used two different development schedules, described in table 42, to determine potential production under base and advanced technology conditions. The schedules represent a rapid early development of the resource. For the base case, tight sands production is 3 TCF in 1990 and rises to nearly 4 TCF in 2000, at $3/MCF (1 977$). The advanced case contributes 4 TCF by 1985 and nearly 8 TCF in 1990 but declines to less than 7 TCF by the year 2000. In contrast, the NPC standard scenario at $5/MCF (1979$) will contribute only 2 TCF by 1990 but up to 9 TCF in the year 2000.

The NPC approach was to assume that there are few external constraints on most of the factors affecting production. Rather than a forecast of the "most probable" production, its supply

[65] According to Ovid Baker, Chairman of the NPC Tight Gas Task Group, deep tight gas below 15,000 ft would cost more than $12/MCF to produce, and the NPC upper limit on price was $9/MCF (Ovid Baker, personal communication, 1984).

**Table 42.-Projections of Annual Tight Gas Production, TCF**

| Assumptions | 1990 | | | | 2000 | | |
|---|---|---|---|---|---|---|---|
| *Lewin:* All drilling begins in 1978 and is completed by 2003. *Base case:* drill probable acreage immediately, lag drilling of possible acreage 9 years; 20 percent DCF ROR. *Advanced case.'* lag drilling of probable acreage 3 years, lag drilling of possible acreage 9 years but complete in 15 years; 10 percent DCF ROR | Price[a] ($/MCF) | Base | | Advanced | Base | | Advanced |
| | **3.00 (4.70)** | **3.2** | | **7,7** | **4.0** | | **6.8** |
| *NPC:* *Standard scenario,* phase in advanced technology, 5 percent by 1983, 100 percent by 1989 in blanket sands; 2 years lag in lenticular sands; 40 percent of most profitable prospects ( > 50% DCF ROR) drilled in first 20 years; 4 years from first drilling to initial production. 2 *times standard:* faster technology development and drilling schedule, 1/2 *standard.'* slower technology development and drilling schedule | Price ($/MCF) 15% ROR | 1/2 std | Standard | 2 X std | 1/2 std | Standard | 2 X std |
| | 2,50 (3.35) | | 1.1 | | | 5.8 | |
| | 3.50 (4.65) | | 1.3 | | | 7.0 | |
| | 5,00 (6.70) | 0.9 | 1.8 | 2,2 | 4.1 | 8,3 | 15.5 |
| | 9.00 (12.00) | | 2.5 | | | 10,5 | |
| *GRI:* Assume average production decline curves, increase in numbers of wells drilled by 200 per year. *Base case.'* begin with 100 wells in 1984 to 800 in 1988 and 10 percent to 15 percent growth beyond 1988. *Advanced case.* begin with 200 wells in 1984; increase to 800 in 1987 with 10 percent to 15 percent growth beyond 1987. | Price[a] ($/MCF) | Base | | Advanced | Base | | Advanced |
| | 3.12 (4.20) | 0.48 | | 0.93 | 1.99 | | 3.44 |
| | 4.50 (6,00) | 0.53 | | 1.02 | 2.51 | | 5,21 |
| | 6.00 (8.00) | 0.57 | | 1,12 | 3.31 | | 6.04 |
| AGA: Price and rate of return not defined; average production decline curve similar to GRI; lower drilling rates than NPC; slower implementation of advanced technology. *Conservative case:* lower initial average production rates to account for areas where massive hydraulic fracturing cannot be used. *Consensus case.'* modified to account for slow technologic development and overlapping conventional and tight definitions. | | Conservative | | High | Conservative | | High |
| | Calculated | 1.1 | | 1.2 | 4.3 | | 6.2 |
| | Consensus | | — | | | 1.2-3[b] | |

aPrice in dollars at the time of the study(1983$)
bRange includes Devonian shale

scenarios are quite deliberately structured to represent a maximum—the amount of gas that could be produced given a concerted effort to develop the required technology and no market restrictions[66] on field development.

The NPC study combines the resource base and economic model to develop several scenarios for production of the tight gas resource. The scenarios incorporate a development schedule in which a certain percentage of the more profitable prospects in all basins are drilled first. Certain constraints were incorporated in the development schedule to reflect the fact that not all the leases on the most profitable prospects will be immediately available for drilling. Development in some areas, such as the Northern Great Plains, is delayed due to lack of pipelines. Advanced technology is phased in according to specific schedules. Annual production rates and cumulative additions to reserves for each scenario

[66]That is, producers can sell all the gas they can produce and transport to potential markets, at the assumed wellhead price plus transportation costs.

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were **calculated for various prices and rates of return. Results of the different scenarios are shown** in table 42.

Figure 33 compares several of the NPC scenarios with the Lewin base and advanced case. The primary difference between the two sets of estimates is the rapidity with which profitable prospects are developed in the Lewin study, and also in the period of time between discovery and actual production from a prospect. In the NPC study, it takes 4 years to place a well under production after drilling; in the Lewin study, production begins the year after discovery.

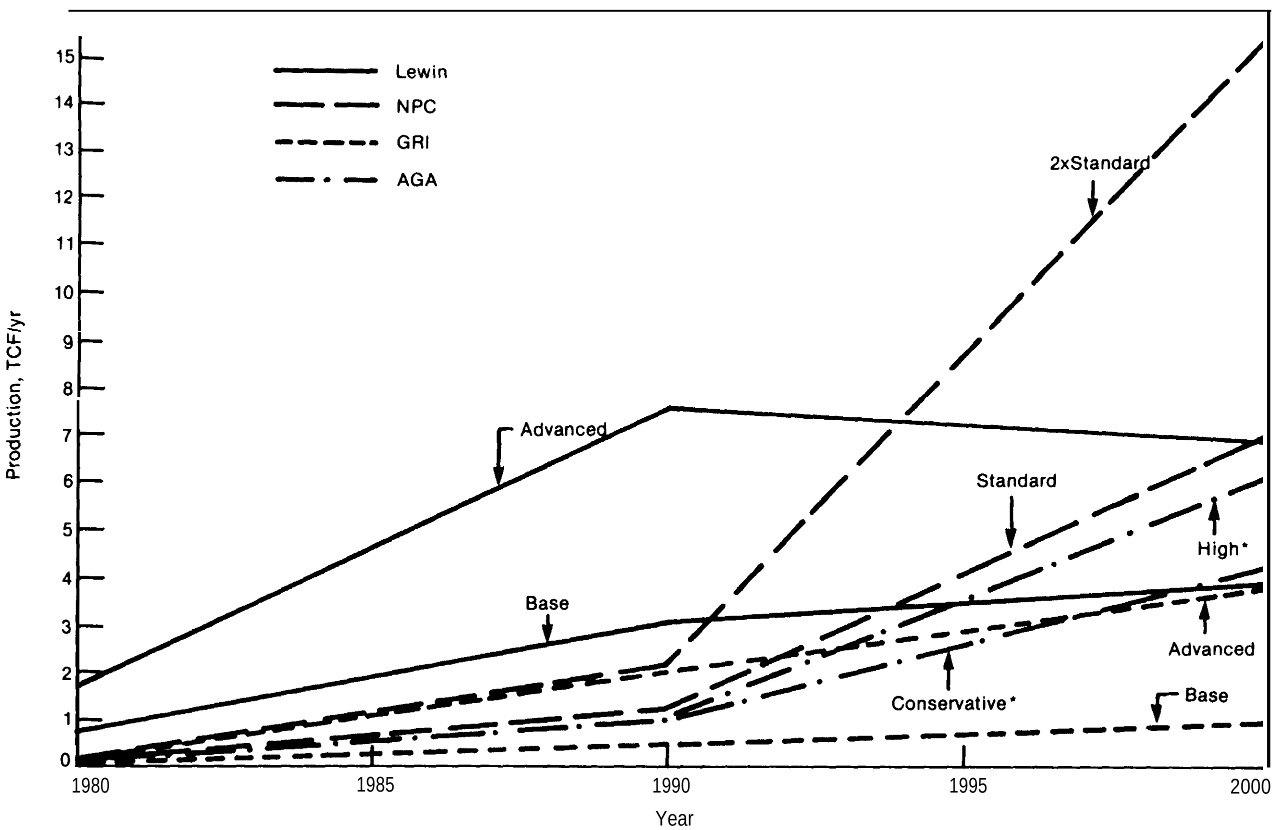
GRI took a slightly different approach to forecasting annual production from tight sands in the earlier (1980) of its two analyses.[67] It determined a production decline curve representative of an "average" well with a production life of 30 years and specified a rate of increase in the number of wells drilled per year. Initial production rates and rate of drilling varied for the base and advanced case scenarios. Details are given in table 42, Its production estimates for base and advanced technology cases range from 0.48 to 1.12 TCF in 1990 and 1.99 to 6 TCF in the year 2000.

A more recent GRI production analysis[68] is based on the TGAS model of the NPC study

[67] J. C. Sharer and J. J. Rasmussen, "Position Paper: Unconventional Natural Gas," *Gas Research Institute*, May, 1981.

[68] J. 1. Rosenberg, F. Morra, Jr., and M. Marchlik, "Future Gas Contributions From Tight Sand Reservoirs, " *1984 International Gas Research Conference,* Sept. 10-13, 1984, Washington, DC.

**Figure 33.-Annual Tight Gas Production Estimates**
**(wellhead gas price = $4.70/MCF, 1983$)**




*No gas price specified.

methodology, but adopts a series of advanced technology assumptions that are more modest than the NPC's. The production projections are based on a price **path** rather than a constant real price, with gas prices assumed to reach $6.20/MCF in 2000 and $7.80/MCF in 2010 (all prices in 1982$), and assuming a 15 percent discount rate. The model is deliberately calibrated to produce a year 2000 base production level at around the average of current projections by AGA and DOE, so the value of the analysis lies in the sensitivity analyses around the base production level (described later), and not the level itself.

The production estimates for the base and advanced technology cases range from 1,9 to 2.7 TCF in 2000 and 2.9 to 5.6 TCF in 2010. An additional set of estimates was made for a case where no limits were set on gas demand, capital and drill rig availability, or level of investment. As might be expected, the production estimates for this case are very high, 8 to 11 TCF in 2000 and 8 to 14 TCF in 2010. The investment and drilling implications of this latter case appear unrealistic, but the estimates give some idea about what might be possible with an emergency development program.

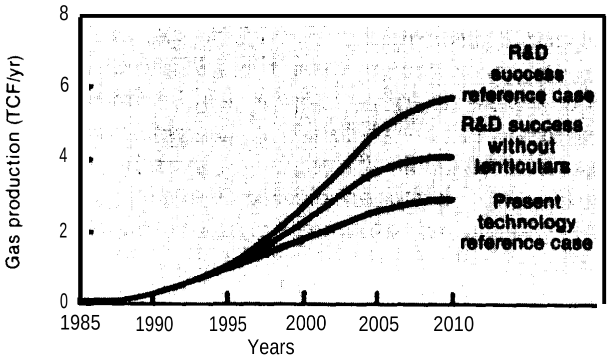
An additional estimate of future production rates is given by the American Gas Association (AGA),[69] AGA used the NPC's analysis as a starting point and superimposed its own assumptions. Its initial estimate projected annual production of 1.2 TCF in 1990 and 6.2 TCF in the year 2000. AGA attributes these lower estimates (relative to the NPC forecasts) to lower drilling rates and a slower implementation of advanced technology. A more conservative estimate, based on lower initial production rates per well, projects 1.1 TCF in 1990 and 4.3 TCF in 2000. No price levels are indicated. AGA suggests that even lower annual production (from 1.2 to 3 TCF from both tight sands and Devonian shales) is likely due to definitional overlap between conventional and tight reservoirs (i. e., some of the production formerly considered to be unconventional more properly belongs in the conventional category) and a less optimistic outlook for the potential of advanced technologies. This lower production range probably is not directly comparable to the NPC's, however, because the AGA definition of unconventional gas appears to exclude gas resources not yet under development that are economically recoverable at today's price and technology—resources that are included in the NPC's tight gas resource base. Such resources, which are in a "grey area" between clearly conventional and unconventional resources, probably make up at least 100 TCF of the NPC's recoverable resource and play a major role in NPC's projected production during the first few decades of tight gas development.

The time frame and extent of technological development is a major factor contributing to the uncertainty of actual production from the tight gas reservoirs. The production of most of the resource contained in the lower permeability formations and the Ienticular formations is strongly dependent on advanced technology development. A slower rate of technology development may severely limit the potential contribution of the tight sands resource to U.S. supply in the next 20 years. For example, NPC made its scenario projections based on immediate utilization of base technology, and implementation of advanced technology in all blanket formations by the year 1989 and in all Ienticular formations by 1991. Events of the last few years have indicated that this rate of development is too optimistic. As discussed previously, the base case technology criteria have not yet been met, especially not in Ienticular reservoirs.

Aside from the **rate** at which new technology will be developed, the advanced technology characteristics assumed by the NPC appear to be quite optimistic, and GRI has used more modest assumptions. However, in reality the specification of future technologies has always been a risky undertaking, and past efforts in other technological areas have not tended to be wildly successful. As shown by figure 34 and by an examination of the "base" and "advanced technology" production projections in each of the studies, the adequacy of exploration and production technology is critical to the economics of tight gas development, and errors in projecting the future state of technology may be translated into sub-

[69]American Gas Association, *The Gas Energy Supply Outlook: 1983-2000*, October 1983.

**Figure 34.—incremental Tight Gas Sands Production Rates As a Function of R&D Advances**




SOURCE: Lewin & Associates, Gas Research Institute.

stantial errors in projecting future production levels at a particular gas price.

Figure 34 shows GRI's projected production levels at current technology, advanced technology, and a modified advanced technology case where the ability to produce lenticular reservoirs not in direct contact with the well bore has never been achieved. Because of the time delay involved in developing and implementing new technologies, the three cases do not diverge until the mid-1990s, but by 2000 the advanced technology case produces about 50 percent more than the current technology case. By 2010, the advanced case produces 100 percent more—5.6 TCF/yr v. 2.9 TCF/yr About half of the additional production would be lost, however, if remote lenses cannot be produced.

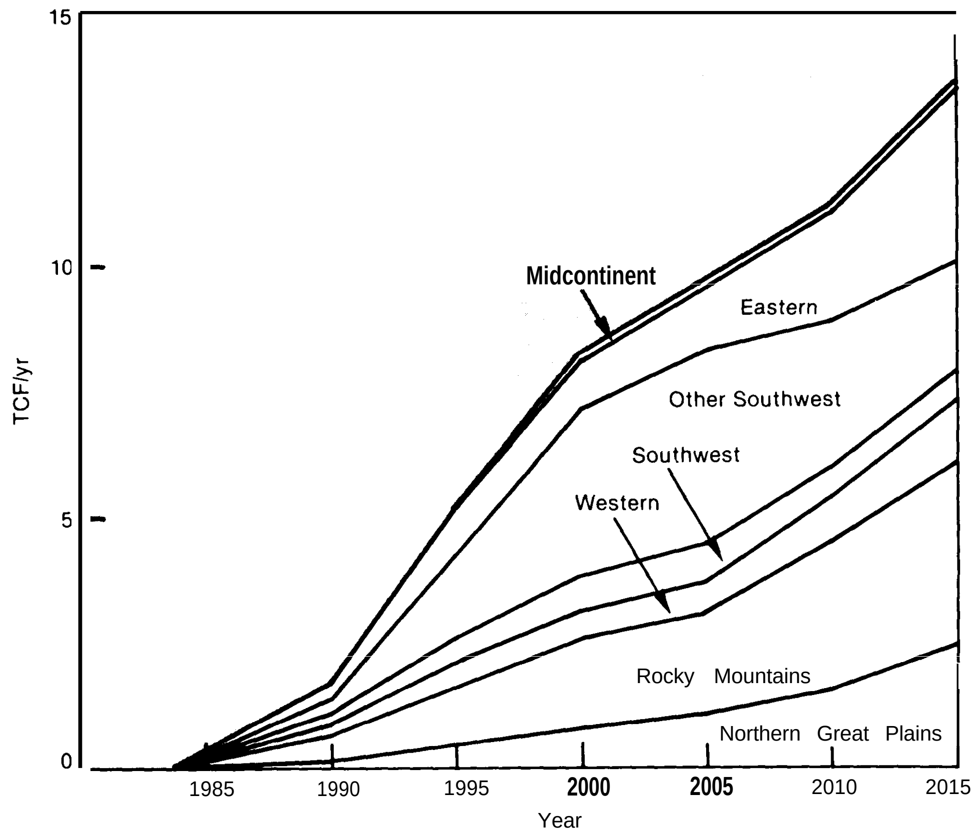
Another important area of uncertainty is the potential for errors in resource assessment. A number of the resource estimates for individual basins have been questioned. Figure 35 breaks out the NPC standard development scenario into the contributions by each basin. In this way, the effect of delaying or otherwise constraining development of certain basins can be more easily visualized. Significant errors in the resource assessments for these basins might be reflected in errors in the production estimates. However, because operators will shift from one target to another if the first does not meet their expectations, the effect on national production of an overestimate of resources in a single basin may include both an overestimate of production **from that area** and a partially offsetting underestimate of production from adjoining areas.

A significant contributor to annual production is the group of Eastern basins. These fall in the extrapolated portion of the resource assessment; recoverable resource estimates for these basins are subject to considerably greater uncertainties than those for the appraised basins.

Another area that deserves particular attention is the Northern Great Plains, which has been the subject of considerable argument concerning the magnitude of its recoverable resource. As illustrated by figure 35, the Northern Great Plains (NGP) plays only a moderate supply role in the NPC standard scenario. One cause of this moderate role may be that the NPC assumed that lack of pipeline availability would significantly delay development in this region. However, the relative development costs of the NGP's shallow gas resource are projected to be quite low, and a supply analysis that assumed fewer supply restrictions would project a more extensive role for NGP gas. Figure 36 illustrates GRI's TGAS projection of tight gas production with and without the NGP, with current and advanced technology. The projection assumes a gradually rising gas price rather than the NPC's constant real price. For both the present and advanced technology cases, removal of the NGP drastically curtails total tight gas production, especially in the short term. For the present technology case, production only "recovers" to about half the reference case by the year 2010. The effect of "losing" the NGP in the advanced technology case is less severe, with production in 2010 about two-thirds of the reference production.

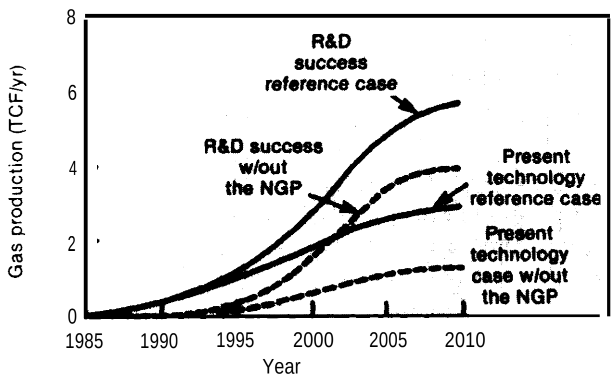
Another potential supply constraint, the total size of the resource, probably will not significantly affect production rates over the next 20 years. in fact, if development of the tight gas resource continues to be as slow as in the last few years, this boundary constraint is not likely to be felt until well into the next century. it may, however, have an impact on the long-term contribution to supply. Comparison of the NPC and Lewin scenarios demonstrates the effect of a smaller total resource on production. Supply from the Lewin appraised resource will begin to decline near the

**Figure 35.—Annual Production by Basin—NPC, $5.00/MCF (1979$), 15°/0 DCF ROR, Standard Scenario**




SOURCE National Petroleum Council.

**Figure 36.—Incremental Tight Sands Gas Production Rates With and Without the Northern Great Plains Resource**




SOURCE Lewln & Associates, Gas Research Institute.

year 2000, apparently due to the boundary constraints imposed by the size of the resource. In contrast, production from the total U.S. resource appraised by the NPC continues to increase well into the next century and remains as a significant source of supply until at least 2040 (NPC report, fig. **27).**

The absence of pipelines in many potential tight sands production regions further constrains near- and mid-term development of the tight sands resource. Development of new regions has always been something of a problem for gas development: pipeline companies cannot get approval to build new lines without evidence of proved reserves, whereas producers are reluctant to drill and prove reserves without the presence of a nearby line. For tight gas fields, pipelines may require evidence of larger reserves than are presently required for conventional fields, because the tighter reservoirs produce more slowly.

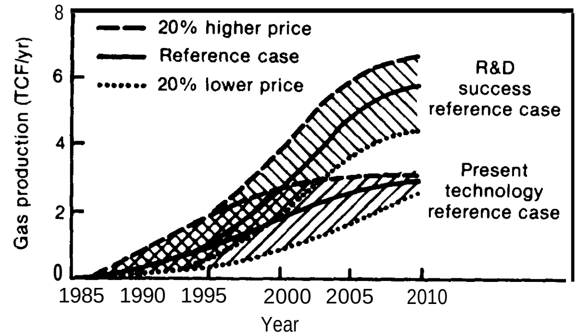
In the short term, pipeline constraints will affect the pattern of development. Fields near existing pipelines will be developed first. Already much of the new production from tight sands fields is coming from the Southwest, which has excess pipeline capacity. In other areas without pipelines, despite potentially large volumes of gas and low estimated costs of extraction, development is likely to be delayed for several years due to lack of pipeline capacity.

Aside from technical considerations, future tight gas production will be dependent on future gas prices and investment discount rates. For example, figure 37 illustrates how production will change if prices are 20 percent higher or lower than the projected values in GRI's analysis. The price variation produces a production variation in the present technology case of about 1 to 3 TCF in the year 2000, a major difference in production for a relatively modest range of gas prices. Similarly, the range of year 2000 production projections for the advanced case will be about 2 to 4 TCF. Because future gas prices are likely to be closely tied to unpredictable oil prices, the chance of estimating year 2000 gas prices to within better than +/- 20 percent—and thus, estimating **production** to better than about +/- 1 TCF—seems remote.

Figure 38 shows the effect of changes in discount rate on production. Discount rate is essentially a proxy for the perceived risk associated with an investment. The range of discount rates—10 to 20 percent–displayed in the figure seems a reasonable measure of uncertainty for the present technology case because the profile of the potential developers, the development climate, and the physical uncertainty associated with development expenditures are not well understood at this time.

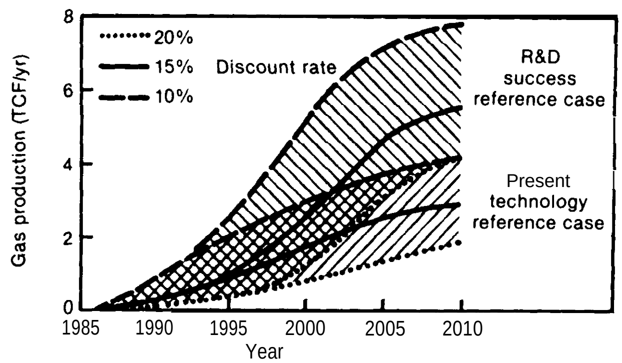
As illustrated by the figure, discount rate is a crucial variable over the entire course of development and for both base and advanced technology. For example, in the year 2000, the 10 point spread in discount rate introduces an uncertainty of about +/- 50 percent in the expected production for the present technology case and + 100 percent, –5o percent for the advanced technology case.

**Figure 37.—incremental Tight Sands Gas Production Rates as a Function of Gas Price**




SOURCE: Lewin & Associates, Gas Research Institute.

**Figure 38.—incremental Tight Sands Gas Production Rates As a Function of Discount Rate**




SOURCE: Lewin & Associates, Gas Research Institute.

In the NPC and Lewin reports, and possibly in the GRI and AGA reports as well, little or no consideration was given to the possibility that market problems might constrain the future production of tight gas. in the past few years, however, declines in gas usage and the widely perceived optimistic prospects for conventional gas supply and price stability have altered even the enthusiasts' perception of the near-term future of tight gas and other forms of unconventional gas, It is generally considered improbable that massive financial resources will be channeled into development of very low permeability formations if ample prospects of conventional gas are available. Consequently, many supporters of the NPC study, while remaining convinced of the accuracy of the gas-in-place and recoverable resource estimates, no longer consider the high production projections to be very likely. To a certain extent, more pessimistic projections of future tight gas production can be self-fulfilling because their acceptance is likely to discourage the research necessary for a major expansion of tight gas production. on the other hand, at least a moderate rate of improvement in tight gas exploration and production expertise and technology will continue regardless of markets, because of continued research on oil production from tight formations and the momentum of existing research programs and tight gas development.

OTA believes that future tight gas development will be closely linked to the availability of conventional gas resources. As discussed in Part I of this report, we do not believe that the year 2000 supply of conventional gas can be projected without a large error band. Consequently, we are skeptical of our ability to reliably project tight gas production to the year 2000 except on a "what if . . ." basis.

On an optimistic basis, we do believe that the year 2000 incremental production of tight gas[70] can reach 3 or 4 TCF/yr, or perhaps even somewhat higher, **if** the present gas bubble ends within a year or two, markets for gas remain firm and real prices increase steadily for the remainder of the century, and the industry is confident of the long-term marketability of tight gas and thus is willing to make the necessary investments in R&D. Such a future is consistent with the pessimistic end of OTA's projected range of 9 to 19 TCF/yr for year **2000** production of conventional gas.

On the other hand, there are plausible circumstances that could stifle future tight gas production, including high conventional gas production and stable or declining real prices, low future demand for gas, or the loss of industry confidence in future gas marketability. A pessimistic scenario might involve year **2000** incremental production of 1 to 2 TCF/yr. Beyond 2000, the size of the recoverable resource, as affected particularly by production technology and the availability of gas in the lenticular basins and the Northern Great Plains, will play a critical role in determining the magnitude of production. In addition, the production rate will always be extremely sensitive to the introduction of any new technological advances affecting production costs and recovery efficiency.

[70] That is, over and above the 1 TCF/yr or so of tight gas produced today that is generally included in "conventional" production figures.

## Chapter 9

# Gas From Devonian Shales

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## TABLES



## FIGURES

# Chapter 9
# Gas From Devonian Shales

## INTRODUCTION

Although it is often presented as a gas source of the future, Devonian shale gas actually has a long production history: the first Devonian shale gas well was drilled in **1821,** near Fredonia, NY, and "modest" production from Devonian shale wells began around the 1920s and has continued to the present.[1] Cumulative production from the shales during all the years of production has been less than 3 trillion cubic feet (TCF), most from the Big Sandy Field in Kentucky and adjacent West Virginia, and current production is only about 0.1 TCF/yr.

Because of its history, Devonian shale gas may be thought of as a "conventional" gas resource. It is also an unconventional gas resource, however, because of its complex geology and because advanced exploration and extraction technologies and higher prices may be able to transform it into an important component of U.S. gas supply from its current status as a very limited, if still locally important, gas source.

'Potential Gas Agency, "Potential Gas Resources From Nonconventional Sources, " *Potential Supply of Natural Gas in the United* States, May 1981.

## CHARACTERISTICS OF THE DEVONIAN SHALE RESOURCE

Devonian shale gas is defined as natural gas produced from the fractures, pore spaces, and physical matrix[2] of shales deposited during the Devonian period of geologic time. As illustrated in figure 39, Devonian shales occur predominantly in the Appalachian, Illinois, and Michigan basins. The shales formed approximately 350 million years ago in a shallow sea that covered the eastern half of what now constitutes the continental United States. organic-rich muds and silts were deposited in the sea and subsequently buried by younger sediments. The high pressures and temperatures that accompanied burial of the sediments resulted in the formation of natural gas from the organic material.

The gas content of the shales is proportional to the amount of organic material, and more precisely the organic carbon, present in the rock. The organic material occurs as microscopically thin layers, alternating with mineral layers. The actual physical color of the shales is indicative of their organic content: black and brown shales generally have higher organic contents and therefore more gas than gray shales.

Other determinants of the gas content are the origin of the organic material, that is, the type of organisms (algae, pollen, woody plants, etc.) that formed the sedimentary layers which became the shale, and the physical conditions, especially the temperature, to which the organic material was exposed. For example, blooms of algae appear to be the major source of Devonion shale gas, whereas terrestrial organisms are less promising sources of gas.[3] And temperature conditions between 60° C (140° F) and 150° C (3020 F) are optimal for the formation of petroleum (oil and gas).[4]

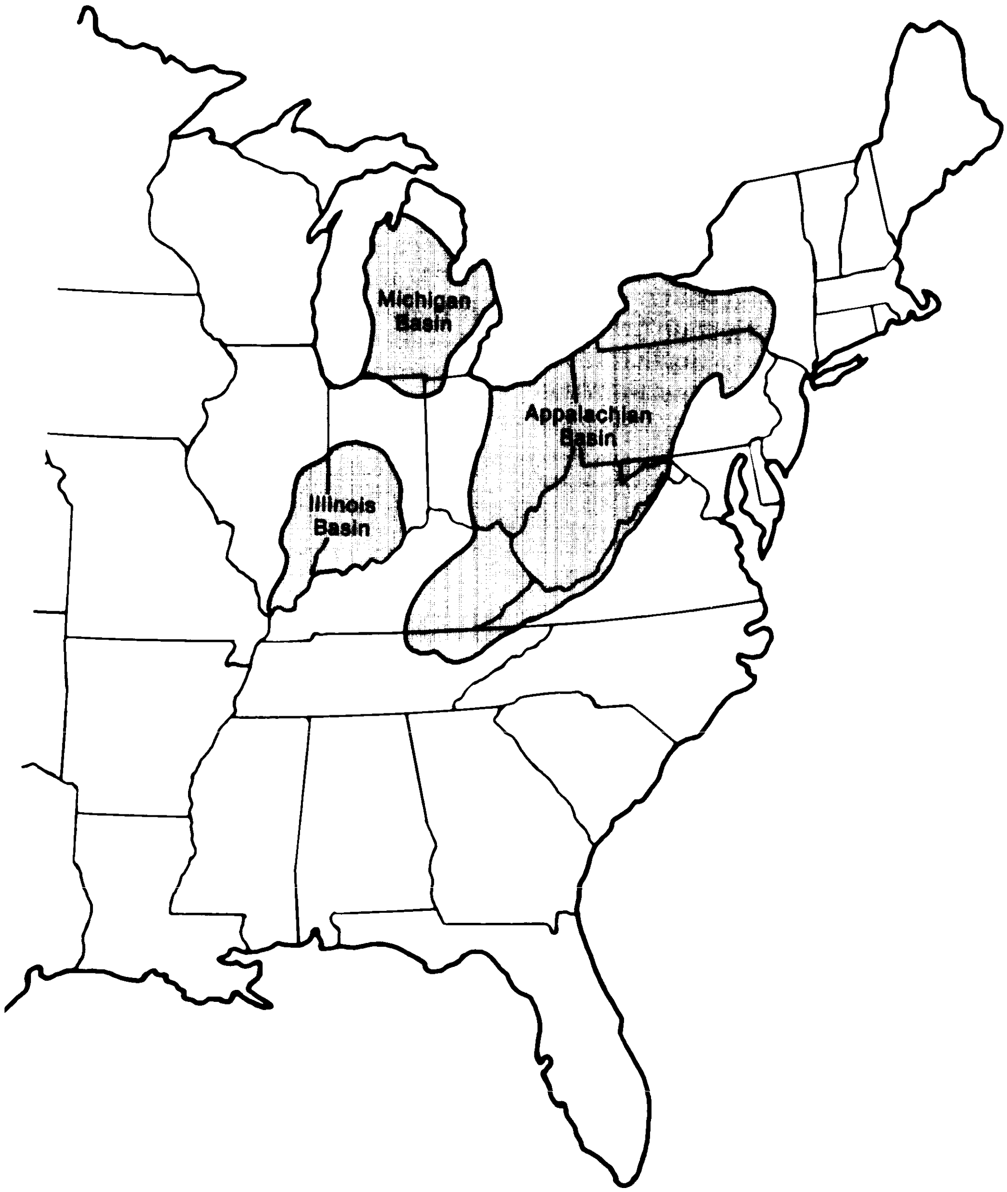
Unlike accumulations of natural gas that are considered conventional, and unlike tight sands gas, Devonian shale gas did not migrate from source rocks to reservoir rocks and accumulate in a trap. Instead, the low permeability of the Devonian shale prohibited most of the gas from escaping. As such, the shale is effectively the source, reservoir rock and trap for the gas. However, some gas originally present in the shale may

'That is, a portion of the gas is adsorbed, or bound, to the actual physical structure of the shale.

[3]R. A. Struble, *Evaluation of the Devonian Shale Prospects in the Eastern United* States, U.S. Department of Energy Report DOE/MC/19143-1305, undated.

[4]J. M. Hunt, *Petroleum Geochemistry and Geology (New* York: Freeman, 1979), p. 617. Cited in R. A. Struble, op. cit.

**Figure 39.—Primary Area of Devonian Shale Gas Potential**




SOURCE: Johnston & Associates, OTA Contractor,

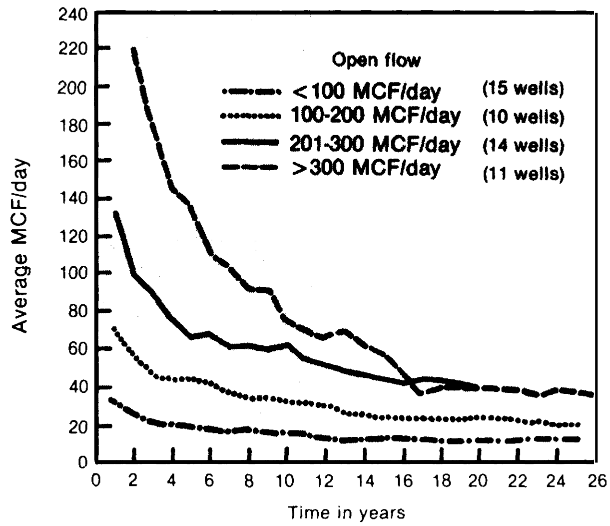
have migrated out of the formation, escaping to the atmosphere or forming conventional gas accumulations in nearby sandstones.

The reservoir characteristics of Devonian shale differ substantially from those of conventional reservoirs. Porosities range from 8 to 30 percent in conventional reservoirs; Devonian shale matrix porosities are generally 1 to 2 percent. The permeability of the shales is also significantly lower. Conventional reservoirs have permeabilities in the range of 1 to 2,000 millidarcies (red), whereas Devonian shale matrix permeabilities generally range from $10^{-5}$ to $10^{-6}$ md. Even though portions of the shale contain natural fractures, fracture permeabilities tend to be low, ranging from about 0.001 to 1 md; in most cases, permeabilities are less than about 0.1 md.[5] As suggested by these statistics, gas flows much less readily from most Devonian shale reservoirs than from conventional sandstone reservoirs.

The natural fractures in the shale, which most often occur in a vertical pattern, are critical to successful production. Such production generally requires intersecting these fractures to utilize the increase in overall permeability that they promote. Because the shale fracture systems in the great bulk of the Appalachian Basin are still quite tight, however, achieving high recovery efficiencies generally also requires inducing new, propped fractures in addition to connecting with the natural system. Also, aside from their “tightness,” the shale fracture systems tend to be somewhat lined up rather than being random in direction–a property called “anisotropy.” Optimum fracture design and well spacing are affected by this property, e.g., a rectangular well spacing pattern aligned with the direction of anisotropy will increase gas recovery over the usual square pattern.[6]

Typically, production from Devonian shale wells is at first relatively high, followed by a steady decline to a base level which can remain constant for over 50 years. Four production curves representing the averaged production of multiple wells are included in figure 40. The shape of the production curves probably is a result of the multiple ways in which the gas occurs in the rock: in pore spaces, in the fracture system and adsorbed to the shale matrix. The initial production is composed primarily of the free gas contained in the fracture network immediately connected to the wellbore and that pore gas which readily migrates to the well bore. The base level then represents the rate at which the gas diffuses through and desorbs from the shale matrix. However, the relative contribution of each of the three distinct “sources” of gas in the shale is not completely

**Figure 40.—Averaged Production Decline Curves for 50 Devonian Shale Gas Wells**




Lincoln, Mingo, and Wayne counties, West Virginia. Wells were metered on open flow after shooting or fracturing of the shale pay zone. MCF = thousand cubic feet. (From Bagnall and Ryan, 1976. ERDA Pub. MERC/SP-76/2. Fig 11, and W. D. Bagnall, personal communication.)

SOURCE: U.S. Congress, Office of Technology Assessment, *Gas Potential From Devonian Shales of the Appalachian Basin (Washington, DC: U.S. Government Printing Office, OTA-E-57, November 1977).*

understood, and there are alternative interpretations of the precise composition of the base production level. One interpretation is that the base level is primarily adsorbed gas that is being released by the shale matrix as the pressure drops. An alternative explanation is that the base level gas is primarily gas from other gas-bearing intervals that are connected to the primary (stimulated) interval by the vertical fracture network in the shale.

Deciphering the relative roles of these two mechanisms is critical to estimating the recoverable resource. At one extreme, if the base level of production is mostly adsorbed gas and there is little communication between gas-bearing intervals, then the intervals that are not currently being stimulated may be available for production in the future. At the other extreme, if there is little resorption of gas and the base level is due to vertical communication between *intervals,* then the number of targets for economic production is drastically reduced and the recoverable resource will be far less. In the latter case, the

[5] V. A. Kuuskraa and D. E. Wicks, “Devonian Shale Gas Production Mechanisms, ” 1984 International Gas Research Conference; V. A. Kuuskraa, et al., *Technically Recoverable Devonian Shale Gas in Ohio,* Lewin & Associates Report for Morgantown Energy Technology Center, July 1982.

[6] V. A. Kuuskraa and D. E. Wicks, “Devonian Shale Gas Production Mechanisms,” 1984 International Gas Research Conference.

**major part of the gas-in-place (Kuuskraa and** Wicks estimate that adsorbed gas represents over 80 percent of the total[7]) will not be available for production with currently foreseen technology. The current available data appear to support the "resorption, little vertical communication" interpretation, but these data are limited to a very small geographical area.[8]

[7]Kuuskraa and Wicks, op. cit.

[8]Charles Komar, Morgantown Energy Technology Center, personal communication, 1984.

# GAS= IN-PLACE RESOURCE BASE

The Devonian shale resource is becoming increasingly well characterized as a result of recent efforts to better understand the geological characteristics of the resource and its size. Work performed as part of the Department of Energy's (DOE) Eastern Gas Shales Project (EGSP) has provided substantive geological and geochemical data.[9]

## Methodologies and Results

**As** illustrated in table 43, several organizations have estimated the size of the Devonian shale resource base. The three most recent estimates of the in-place resource were made by the National petroleum Council (NPC) in June 1980 and the U.S. Geological Survey (USGS) and the Mound Facility (operated by Monsanto Research Corp.) in 1982. The NPC study evaluated the Devonian shale resource in the three shale basins, whereas the other two restricted their estimates to the Appalachian Basin.

[9]The results of the project are summarized in a report by R. A. Struble, *Evaluation of the Devonian Shale Prospects in the Eastern United States,* U.S. Department of Energy Report DOE/MC/19143-1305, undated. This report provides a comprehensive review of the "state-of-the-art" of Devonian shale resource analysis up to about 1982.

## National Petroleum Council[10]

The NPC estimated the gas-in-place resource for each of the three major basins. The primary variables in the in-place resource calculation were shale thickness, areal extent and gas content, with gas content assumed to be uniform throughout each basin. These parameters were established differently for each basin, depending on the type and quantity of information available.

locational Petroleum council, "Unconventional Natural Gas-Devonian Shales," June 1980.

**Table 43.-Devonian Shale Resource Base Estimates (TCF)**

| Organization | Year | Basin evaluated | Estimate |
|---|---|---|---|
| National Petroleum Council[a] . . . . . . . . . . . . . . . | 1980 | Appalachian . . . . . . . . . . . . . . . . | 225 to 1,861 (125 to 1040[b]) |
| | | Michigan . . . . . . . . . . . . . . . . . . | 76 |
| | | Illinois. . . . . . . . . . . . . . . . . . . . . | 86 |
| U.S. Geological Survey[c] . . . . . . . . . . . . . . . . . . . | 1982 | Appalachian . . . . . . . . . . . . . . . . | 577 to 1,131 |
| Mound Facility[d] . . . . . . . . . . . . . . . . . . . . . . . . . | 1982 | Appalachian . . . . . . . . . . . . . . . . | 2,579 (l,440[b]) |
| Lewin & Associates[e] . . . . . . . . . . . . . . . . . . . . . . | 1980 | Appalachian . . . . . . . . . . . . . . . . | 400 to 2,000 |
| Federal Energy Regulatory Commission[f] . . . . | 1978 | Appalachian . . . . . . . . . . . . . . . . | 285 |
| Smith[g] . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . | 1978 | Appalachian | 206 to 903 |

aNational Petroleum Council, Unconvenyional Gas Sources, *Tight* Gas *Reservoirs Part 1, December 1980.*
*bConsidering* "drillable" area only.
CR.R. Charpentier et al., Estimates of Unconventional Natural Gas Resources of the Devonian Shale Of the *Appalachian Basin, USGS* Open-File Report 82-474, 1982.
dR, E, Zielinski and R D, Mclver, Resource and *Exploration Assessment of* the *oil and Gas* Potential in *the Devonian shales of the Appalachian Basin, DOE/DP/0053-1 125,* undated.
eV. A. Kuuskraa and R. F. Meyer, "Review of World Resources of Unconventional Gas," in IIASA Conference on Conventional and Unconventional World Natural Gas Resources, Laxenburg, Austria, June 30-July 4, 1980.
fU.S., Department of Energy, *Nonconventional Natural* Gas Resources, Report DOE/FERC-0010, 1978.
gE. C. Smith, "A Practical Approach to Evaluating Shale Hydrocarbon Potential," in *Second Eastern Shales Symposium, Vol. II,* U.S. Department of Energy, Report METC/SP-7816, 1978, pp. 73-87.

SOURCE: Office of Technology Assessment.

In each basin, the black and gray shale thicknesses were multiplied by their respective gas contents and their areal extents to arrive at the gas-in-place estimate for the basin.

In the Appalachian Basin, the gas-bearing zone includes the gray and black shale units that overlie the Onandaga limestone and underlie the Berea sandstone. The thickness of the black shales was determined in two ways: first, by gamma-ray well log data which detects the high radioactivity content characteristic of organic-rich shales; second, by thicknesses determined visually from core sample color. The two black shale thickness calculations yield substantially different results, which in turn yield very different gas-in-place estimates. The gas content of the shales was determined through off-gassing data from rock core samples.[11] Values of 0.6 and 0.1 cubic feet of gas per cubic feet of Appalachian shale were obtained for black and gray shales, respectively. The areal extent of the Appalachian shale was determined to be 111,100 square miles.

The gas-bearing unit in the Michigan Basin is the Antrim shale, which extends over 35,400 square miles and contains both black and grey shales. The thickness of the Antrim was determined strictly by well logs and is poorly defined where the Antrim grades into the barren Ellsworth shale in the western portion of the basin. Also, there were no core samples available for off-gassing experiments to determine the quantity of gas present in the unit. In the absence of these data, the gas content of the Michigan Basin shales were assumed to be the same as those of the Appalachian Basin on the basis of similarities in the well production data for the two basins.

The New Albany shale group, covering 28,150 square miles, is the gas-bearing unit in the Illinois Basin. Neither gamma-ray well log data nor core sample data were available to determine the thickness of the units, and therefore the black and gray shale thicknesses could not be differentiated. The thickness of the entire sequence was determined from USGS maps and used in a simple volumetric resource calculation. off-gassing data from cores were available to determine the gas content. The thickness of the sampled units in proportion to the total group thickness was used to establish a weighted average of 0.62 cubic feet of gas per cubic foot of shale for the entire New Albany group.

The results of the NPC study suggest that estimates of the quantity of gas present in the Appalachian Basin are sensitive to the assumed thickness of the black shale and to the inclusion or exclusion of the lower quality gray shales. Based on thicknesses determined by gamma-ray logs, and including only the black shales, the gas-in-place is estimated to be 225 TCF. Based on black shale thickness determined visually from USGS samples and including the gray shales, 1,861 TCF is estimated to be present. (The range for the black shales only is 225 to 1,102 TCF.) If areas that are not drillable[12] are excluded, the gas-in-place estimate is reduced to 125 and 1,040 TCF for the log and sample thicknesses, respectively, The gas-in-place estimates for the Michigan and Illinois basins are 76 and 86 TCF, respectively, but are more uncertain because of the lack of data.

## U.S. Geological Survey[13]

The USGS estimate of Devonian shale gas in the Appalachian Basin recognizes three categories of shale gas: macrofracture gas, micropore gas, and that gas which is adsorbed, or attached, to the clay matrix. Unlike the early Lewin & Associates study (1 978-79), the USGS attributes only a small amount of the total volume of gas-in-place to macrofractures; it assumes that most of the gas is in micropores or bound to the organic matter in the shale matrix.

The Appalachian Plateau province and a small segment of the Valley and Ridge province were divided into 19 areas, termed plays. The characteristics of each play were described in terms of physical location, unit names, thickness, organic content, maturation level and type of hydrocarbon present, tectonic or structural attributes, and, subsequently, a brief description of the produc-

[11] Off-gassing measures the amount of gas that desorbs from a known volume of core over a specific period of time.

[12] Because of difficult terrain, presence of buildings and other development, designation of the land as protected parkland, etc.

[13] R. R. Charpentier, et al., *Estimates of Unconventional Natural Gas Resources of the Devonian Shale of the Appalachian Basin,"* U.S. Geological Survey Open-File Report 82-474 (preliminary), 1982.

tion potential of the play. The volume of gas for each of the 19 different areas was calculated using Equation 1, below:

$$\begin{aligned} G = {} & [\emptyset\,\text{macro} \times TH_s \times Pr/Ps \times \tfrac{1}{2} \times \text{area} \times (5{,}280\ \text{ft/mi})^2] && \text{macrofracture} \\ & + [\emptyset\,\text{micro} \times TH_s \times \text{area} \times (5{,}280\ \text{ft/mi})^2] && \text{micropore} \\ & + [SOR \times ORG \times TH_s \times \text{area} \times (5{,}280\ \text{ft/mi})^2] && \text{adsorbed} \end{aligned}$$

The parameters used in the equation are explained in table 44. The volume of gas for each area was summed to obtain a total basin estimate.

The analysis explicitly recognizes two severe data problems:

- limited quantity of data for most of the assessed area, and
- large sampling errors and differences in interpretation.

Because of the limited quantity and quality of data, a range rather than a point estimate of the gas present was developed. The Monte Carlo method of estimation was employed to acquire the range.[14]

[14] In using a Monte Carlo method, appropriate variables in the equation are specified by a probability distribution rather than by a point estimate. Then, the equation is "solved" for the dependent variable–in this case, gas-in-place–a large number of times by randomly sampling the probability distributions. In this way, a probability distribution is obtained for the dependent variable (gas-in-place). The "solution" to the equation can either be expressed by the probability distribution itself, by its mean or median, or perhaps by a range defined by some probability that the actual value is within its borders (e. g., "there is an 80 percent probability that the correct value is in the range X to Y").

**Table 44.—Equation Parameters**

| Symbol | Meaning |
|---|---|
| G | gas-in-place |
| 0 rnacro | average macrofracture porosity as a fraction of total volume |
| $TH_s$ | average thickness of organic-rich shales |
| $P_r$ | average reservoir pressure (psi) |
| $P_s$ | standard pressure (14.73 psi) |
| $T_r$ | average reservoir temperature (oR) |
| $T_s$ | standard temperature (520°R) |
| z | gas deviation factor (0.9) |
| Area" | area (square miles) |
| 0 micro | average content of microporosity gas at standard temperature and pressure as a fraction of rock volume |
| SOR | average volume ratio of adsorbed gas to inorganic content |
| ORG | average organic content as fraction of rock volume |

SOURCE U S. Geological Survey, "Estimates of the Unconventional Natural Gas Resources of the Devon Ian Shale of the Appalachian Basin, " 1982

The data used were acquired from a variety of sources. The configuration of the gas shales was taken from geologic cross sections, isopachs (thickness maps), and other geological maps compiled by the USGS. Maps were also used to estimate thickness, organic content and average depths, which when combined with temperature and pressure gradients yielded average reservoir pressures and temperatures. Micropore gas estimates were achieved by plotting gas content—acquired from off-gassing data from canned core samples—against the amount of organic matter in the sample. The slope of the resultant curve represents the ratio of adsorbed gas to organic matter. The intercept (gas content at the point where organic matter is zero) represents the micropore gas content.

The results of the USGS study are compiled in table 45. The 95th fractile ($F_{95}$is a low estimate and signifies that there is a 95 percent chance that there is more than 577.1 TCF present. The 5th

**Table 45.—Estimates of In-Place Natural Gas Resources in the Devonial Shale of the Appalachian Basin**

| | Natural gas resources (trillions of cubic feet) | | |
|---|---|---|---|
| Play | Low $F_{95}$[a] | High $F_5$[a] | Mean |
| 1. North-Central Ohio | 17.9 | 34.2 | 25,9 |
| 2. Western Lake Erie | 21.7 | 31.3 | 26.5 |
| 3. Eastern Lake Erie | 2.1 | 3.3 | 2.7 |
| 4. Plateau Ohio , | 44.4 | 76.2 | 59.9 |
| 5. Eastern Ohio | 35.2 | 55.1 | 44.7 |
| 6. Western Penn-York. | 20.4 | 28.2 | 24.3 |
| 7. Southern Ohio Valley. | 19.7 | 36.2 | 27.7 |
| 8. Western Rome Trough. | 38.0 | 74.0 | 56.0 |
| 9. Tug Fork | 13.7 | 25.9 | 19.7 |
| 10, Pine Mountain | 10.7 | 18.7 | 14.6 |
| 11. Plateau Virginia | 3.9 | 10.2 | 7.1 |
| 12, Pittsburgh Basin | 76.8 | 129.9 | 102.1 |
| 13. Eastern Rome Trough | 70.7 | 132.5 | 100.3 |
| 14. New River | 38.5 | 91.7 | 63.1 |
| 15. Portage Escarpment | 8.5 | 21.3 | 14.6 |
| 16. Cattaraugus Valley | 10.4 | 23.2 | 16.6 |
| 17. Penn-York Plateau | 98.1 | 195.2 | 146.0 |
| 18. Western Susquehanna. | 24.1 | 67.7 | 44.9 |
| 19. Catskill | 22.1 | 75.8 | 47.6 |
| Entire basin | 577.1 | 1,130.9 | 844.2 |

NOTE: All tabulated values were rounded from original numbers. Therefore, totals may not be precisely additive.

[a] $F_{95}$ denotes the 95th fractile; the probability of *more than* the amount $F_{95}$ is 95 percent. $F_5$ is defined similarly. Because of dependency between plays, these fractiles (unlike those in many other studies) are additive.

SOURCE U.S. Geological Survey, "Estimates of the Unconventional Natural Gas Resources of the Devonian Shale of the Appalachian Basin, " 1982 fractile ($F_5$ is a high estimate and indicates that there is only a 5 percent chance of there being more than 1,130.8 TCF present.[15] The mean estimate is 844.2 TCF. Although the USGS did not estimate recoverability, it compiled a map illustrating shale gas potential (fig. 41) which qualitatively indicates the potential for recovery in each area based on gas-in-place and the presence of natural fracture systems.

## The Mound Facility[16]

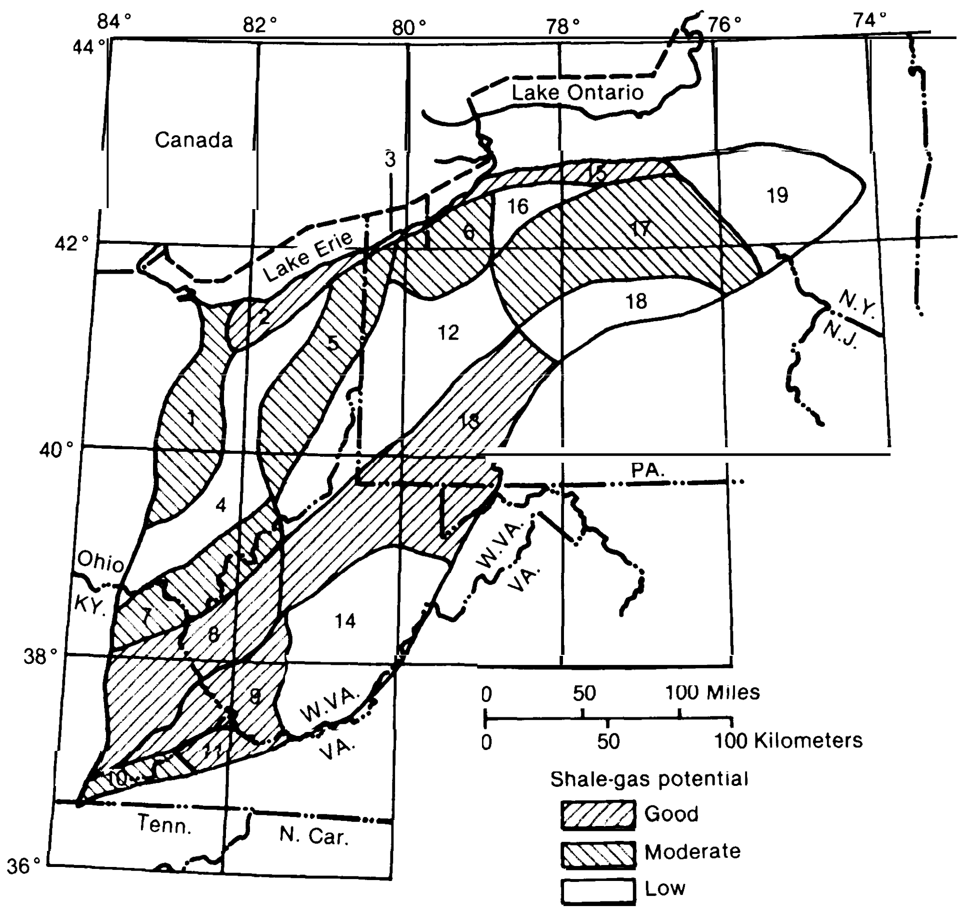
The Mound study incorporates extensive geochemical data into its volumetric analysis of the gas-in-place in the Appalachian Basin. Organic geochemical analyses were performed on over 2,000 individual core samples and on an additional several hundred well cuttings to evaluate the quality of the shale units as sources of natural gas and other hydrocarbons. In particular, the analyses focused on three primary determinants of gas content: the quantity of organic carbon present, its origin (i.e., the nature of the organic material that provided the carbon, e.g., spores, pollen, herbaceous plants, algae, etc.), and its thermal maturity .17

[15] Consequently, there is a 90 percent probability that the gas-in-place is within the range 577.1 to 1,130.8 TCF.

[16] R. E. Zielinski and R. D. McIver, "Resource and Exploration Assessment of Oil and Gas Potential in the Devonian Gas Shales of the Appalachian Basin, " 1982.

[17] Thermal maturity is the extent to which the organic matter in the rocks has been "cracked" by heat. Cracking is the process by which long hydrocarbon chains are broken to form simpler molecules such as those comprising methane gas.

**Figure 41 .—Shale Gas Potential in the Appalachian Basin**




SOURCE USGS, "Estimates of Unconventional Natural Gas Resources of the Devonian Shale of the Appalachian Basin, " 1982

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**Several general conclusions were formulated about the resource potential of the Appalachian Basin. The most important conclusion is that the Devonian shales are exceptionally rich source rocks;** were it not for their low porosity and permeability, the shales would represent "one of the greatest oil- and gas-producing provinces of the world."[18] Other conclusions point to the nonuniformity of the resource and establish where the generally rich nature of the source rocks may not apply. For example, the quantity of organic material in the basin decreased to the east. The organic-rich rocks in the extreme northwestern and western portion of the basin had high potential for hydrocarbon development, but they were only slightly thermally altered and never reached their full gas-bearing potential. In the deeper portions of the basin, too much heat was generated, thereby lessening the potential for finding hydrocarbons.

The gas-in-place analysis differed from the other estimates in the way in which the gas content was determined. Mound felt that a large portion of the gas escaped during the process of obtaining the core and before the core could be sealed in the gas-tight canister, To improve the accuracy of the measurement, Mound developed a controlled off-gassing experiment where the rate of gas release from the core is measured. Data from these experiments were used in combination with other geologic and geochemical characteristics of the formations to develop equations which determined the "indigenous," or original, gas contents of the rock. The methodology was verified by the use of a pressurized core barrel, which extracts the core under in-situ pressure, thereby limiting premature gas release. Mound thus concluded that the revised values more accurately reflected the quantity of gas originally present in the rock.

The gas-in-place estimates were determined for each of 17 separate stratigraphic intervals, or units, in the Appalachian Basin by first combining the indigenous gas contents (MCF/acre-foot) with the thicknesses of the gas-bearing shale to provide the areal distribution of the total gas in each unit. The data were contoured, as illustrated in figure 42. Next, the acreage contained within each contour area was integrated, multiplied by the appropriate gas areal density (MCF/acre), and summed to yield the total gas-in-place for the unit. This methodology resulted in a gas-in-place estimate for the 17 units composing the Appalachian Basin of 2,579 TCF.

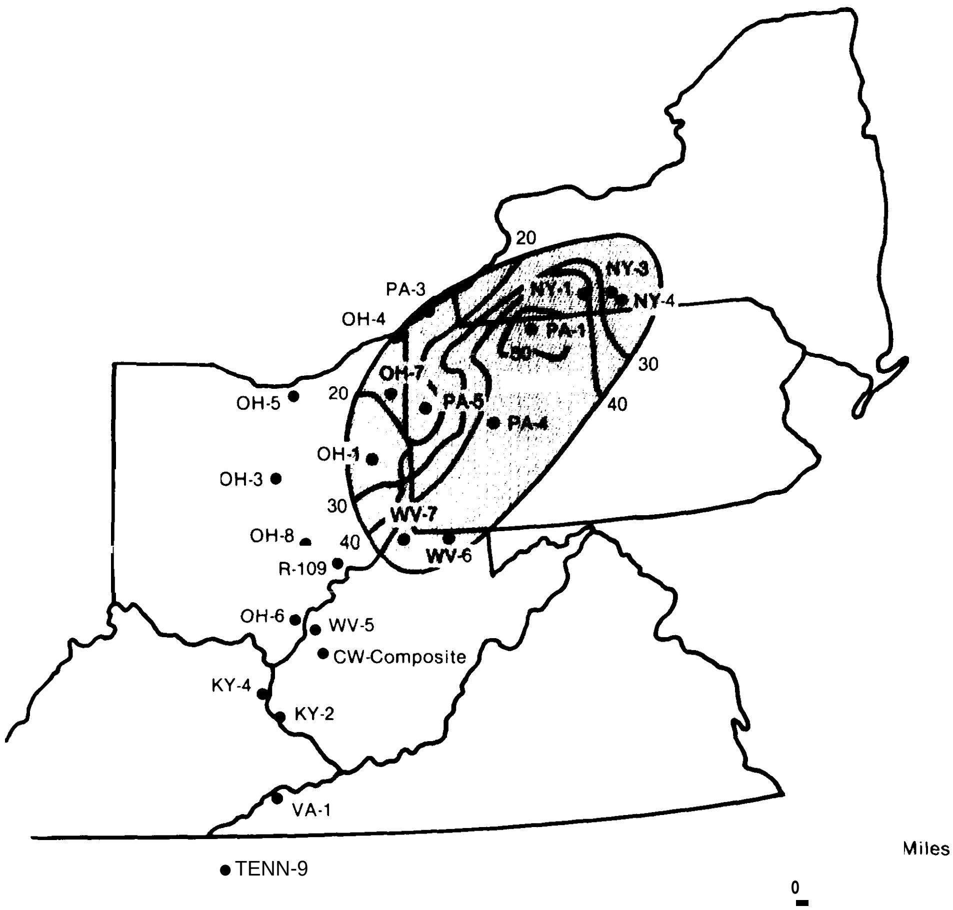
## Estimate Comparison and Uncertainties

The methodologies used by NPC, USGS, and Mound to determine the gas-in-place are all volumetric estimates based on multiplying gas content, shale thickness, and areal extent, but they differ substantially in their computation methods and input data. The major difference appears to be in the computation of gas content. NPC used a basin-wide average based on off-gassing data available at the time. Both the Mound and USGS analyses use a more sophisticated, disaggregate approach, with USGS calculating separately the macrofracture, microporosity, and adsorbed (bound) gas for 19 areas in the Appalachian Basin, and Mound determining gas contents for 17 stratigraphic units in the basin using equations based on geochemical analysis, and contouring and integrating the results across the basin. Both the USGS and Mound estimates had access to new off-gassing data developed by the Eastern Gas Shales Project. The Mound approach is the most optimistic of the three because it incorporates a calculation of gas lost in obtaining and measuring the core samples, a factor not considered by the NPC and apparently not considered significant by the USGS.

**In OTA's** judgment, the physical evidence cited and calculations made in the Mound report appear plausible; the Mound estimate of 2,579 TCF gas-in-place (1,440 TCF in "drillable" areas) seems a reasonable estimate **given the available data.**

[18] R. E. Zielinski and R. D. McIver, "Synthesis of organic Geochemical Data From the Eastern Gas Shales," SPE/DOE 10793, in Proceedings of the Unconventional Gas Recovery Symposium, May 16-18, 1982, Pittsburgh, PA.

**Figure 42.— Distribution of Devonian Shale Gas**
$\left(\frac{\text{MCF Gas/Acre}}{100}\right)$




Stratigraphic interval: early marcellus time
SOURCE: Zielinskl and Mclver, 1982,

# TECHNOLOGY

## Fracturing

Because of the extremely low permeability of the shales, production of Devonian shale gas depends on exploiting the natural fracture network in the rock and on enhancing gas flow by artificially stimulating the well. Over 90 percent of all Devonian wells require stimulation in order to yield gas in commercial quantities, and even stimulated wells will not be successful unless there is already a well-developed natural fracture network.

For most of the Devonian shale's production history, wells were stimulated by filling large portions of the wellbore with explosives and allowing the detonation to shatter the rock surrounding the well. This basic method was first used in 1865 and is still in use. It generally is considered less of a "fracturing" method than simply as a means to overcome the formation damage caused by drilling in the shales. (Its primary structural effect is to fragment the rock immediately surrounding the well bore.)

As in the tight sands, hydraulic fracturing is becoming increasingly used today in the shales. The fractures being created in the shale formations are small, however, not the massive 1,000-ft fractures becoming more popular in the Western tight sands. They also generally carry less proppant than in the sands. The shales are extremely sensitive to formation damage during fracturing, especially because of the presence of water-sensitive clays in the shale that can be dislodged by the fracturing fluids and plug pores and fractures. Although formation damage is a problem with tight sands and coal seams also, Devonian shales may be the most sensitive. Devonian shales have, as a consequence, served as a testing ground for a number of new fracturing fluids.

Many of the fluids developed to minimize formation damage are foamed, using a gas phase to reduce the amount of water required. **Foamed fluids** are gas-in-water emulsions, where the surface tension of the bubbles holds the proppant–particles that become wedged in the fractures and hold them open–in suspension. Nitrogen ($N_2$ is the most common gas used. Properties that make foam suitable for the Devonian shale include low volumes of water, high efficiency in creating fractures, high proppant-carrying capacity, low friction during pumping, and sufficient energy within the gas phase to allow recovery of most of the fluid without pumping. By 1980-81, foam technology had advanced so rapidly that it dominated fracturing in the Devonian shales.

**Pure nitrogen** has also been used as a fracturing fluid. It is not an efficient fracture fluid and can only be used to fracture small depth intervals of 10 ft or so.[19] In addition, it is not an effective carrier of proppants, and consequently is effective only at shallow depths where the fractures are less likely to close. However, nitrogen does not adversely affect the formation and it has proven very effective in increasing gas flow. As a result, nitrogen fracturing quickly became the preferred method for many production situations. Because of the newness of this type of treatment and its relative lack of propping effectiveness, the ability of nitrogen fracturing to maintain production levels over the long-term is uncertain.

Current trends in fracturing technology are centered on the developing of fluids that are both nondamaging, like nitrogen, and can carry proppants more effectively. possibilities include:

- **Stabilized foam.–Although similar to the original foams, water has been reduced from 25 to 10 percent, and proppant-carrying capability is enhanced by a gelling agent that stiffens the foam. This is a high cost method that has been used only sparingly.**
- **Liquid carbon dioxide.–This method has the ability to transport proppants. As the liquid $CO_2$ warms, it reverts to the gas phase and easily flows back out of the hole with minimal damage to the formation. Liquid $CO_2$ fracturing is a relatively expensive process and somewhat** more dangerous to use than foamed fluids. In addition, the casing and pumping materials must be capable of withstanding very low temperatures.
- Shale oil.—This method combines a nitrogen-driven fracture with the subsequent injection of shale oil—obtained from previous drilling–as a proppant-carrying agent to prevent fracture closure.
- **Water-based nonreactive solvents.–These** solvents can be used either after a fracture to clean the formation or as the fluid base of a stabilized foam fracturing treatment. This system is still experimental.

Finally, producers have attempted the use of radically improved versions of the original explosive fracturing used since the 1800s. In tailored **pulse loading,** a propellant charge is ignited to pressurize the wellbore at a much slower rate than is achieved with conventional explosives.[20] The loading rate, or rate at which the energy stored in the propellant is released, can be controlled to create different types of fractures. For

[19] For example, a nitrogen fracture might affect only the reservoir rock between 900 and 910 ft in depth.

[20] J. W. Crafton, "Fracturing Technologies for Gas Recovery From Tight Sands, " OTA contractor report, September 1983.

example, at intermediate loading rates, multiple fractures form radially around the well bore.[21] At slow rates, fractures form in an analogous manner to hydraulic fractures, directionally controlled by the regional stress field.

This technique has only been used on a small scale for prefracturing tests.[22] However, it is thought to have significant potential for use on a larger scale, especially because it causes little formation damage. Commercial application in the Devonian shales may occur in the near future.

The record of success of well stimulations in Devonian shales is mixed. Although new stimulation technologies have increased gas production from a number of wells, many have not benefited from stimulation and the specific reasons for their lack of success are not well understood.

One problem is the local variability and unpredictability of fractured zones. Wells offset short distances from producing wells may not intersect a productive fracture system.[23] Improved technologies or exploration strategies to locate and characterize fracture systems are critical to economic development of Devonian shales.

Another problem is the difficulty in extrapolating successful stimulation techniques from one site to another. Although some producers have been quick to try the newest in technologies, no one has yet established criteria for choosing tailored pulse loading over nitrogen or perhaps liquid $C0_2$ injection. Most stimulations appear to be conducted *on* a trial-and-error basis and inadequate records are kept to determine the reasons for success or failure of a particular technique.

A third problem in successful Devonian shale gas production is accurately determining the pay interval. Because many wells do not have significant gas shows prior to stimulation, it is difficult to determine the interval within the shale sequence which is most likely to contain recoverable gas. Consequently, fractures may not be properly located to optimize production.

Finally, no technology now exists or is being considered to produce gas from those portions of the Devonian shales where the natural fracture system is not well developed. This severely limits the overall production potential of the resource.

## Deviated and Directional Drilling

The only other technology that currently has any potential for increasing production in unconventional reservoirs is one that allows drilling wells that either intersect more of the reservoir rock or intersect more of the natural fracture system. Thus, if reservoirs lie in an essentially horizontal plane and natural fracture systems in a more or less vertical plane, a well drilled at some angle from the vertical would intersect more gas-productive natural fractures.

Directional drilling has frequently been suggested as a technology applicable to Devonian shale gas production .24 Production requires intersection of natural fractures and most of these fracture systems are vertical. The major drawback is the problem of formation damage. A drill bit drilling at an angle from the vertical encounters increased frictional resistance and, if drilling in a fractured formation, runs a greater risk of having the wellbore collapse. Drilling muds are needed to reduce friction and hold the hole open; however, drilling muds may cause considerable formation damage. One experimental deviated well has been drilled in the Devonian shale, in Meigs County, Ohio, but its intent was more to determine the natural fracture spacing than to test a new production technique.[25]

## Exploration

Unlike the sophisticated exploration techniques used in frontier areas such as the Western *Over-*

[21] The radial fractures possible with tailored pulse loading may have special potential in areas where the natural fracture systems in the shale display strong directional tendencies. Radial fractures may outperform long hydraulic fractures when these tendencies (permeability anisotropies) are substantial (Kuuskraa and Wicks, 1984, op. cit.).

[22] Johnston & Associates, Inc., "The Status and Future of Production Technologies for Gas Recovery From Devonian Shales, " OTA contractor report, 1983.

[23] 1 bid,

[24] Office of Tech nology Assessment, "Status Report of the Gas Potential From Devonian Shales of the Appalachian Basin, " 1977.

Z> Charles Komar, Morgantown Energy Technology Center, personal communication, 1984.

thrust Belt and offshore, the "exploration techniques" used for locating Devonian shale wells are often little more than near-random selection based on the availability of land. The failure to use sophisticated exploration technology reflects a number of factors. First, it is difficult to build an exploration block of any size in the Appalachian shale basin because of the diversity of land ownership. Second, leasing problems—e.g., the lack of well spacing requirements in some States in the shale area—aggravate the problem because wells on adjacent properties can get as close to a successful well as the property line allows. There is little incentive to invest in expensive seismic surveys if the costs cannot be recaptured by exclusive development of the surveyed area. Third, existing technology is not fully effective in locating the subsurface features whose understanding is critical to drilling success, and the steep terrain drives up the cost of techniques such as reflection seismology.

Aerial and satellite imagery may prove useful in Devonian shale exploration because they can identify lineaments—characteristic topographic features–which may be related to fault and fracture zones and may contain information on regional stress patterns. Concentrations of surface fractures may indicate the presence of subsurface fracture networks that could serve as potential reservoirs.[26] Skeptics feel that surface expression of fractures does not accurately reflect subsurface conditions (i.e., fractures may curve at depth or may not extend to the gas-bearing rocks). To support their position, they cite failures of wells offset from producing wells along a surface lineament.[27]

Subsurface mapping of variations in the rock formations is also important in the shale region. **A** key mapping tool for the shales is well logging using a combination of gamma-ray and neutron-density logs. Induction logs, spectral logs, thermal decay logs, noise logs, and temperature logs are often run in combination with the gamma-ray and neutron-density logs. Some operators also rely on a combination of gamma-ray, bulk-density, and resistivity logs. (For a brief description of the various types of well logs, see box B-1 in app. B.) Unfortunately, current well logging techniques are not adequate to detect open fractures that do not actually intersect the boreholes, so they are only of limited use in mapping fracture patterns. Also, some States in the shale basins do not require full disclosure of well log data, and this further limits the ability to construct useful subsurface maps from the existing data.

[26] R. D. McIver, J. R. Kyle, and R. E. Zielinski, "Location Of Drilling Sites in the Devonian Shales by Aerial Photography, " SPE/DOE 10794, SPE/DOE Unconventional Gas Recovery Symposium, pp. 51-53.

[27] Johnston & Associates, inc., op. cit.

## RECOVERABLE RESOURCES AND PRODUCTION POTENTIAL

The Devonian shale gas-in-place resource in the Appalachian Basin has been estimated at between 225 TCF (the NPC low estimate) and 2,579 TCF (the Mound estimate). As discussed above, the higher end of the range appears most credible on the basis of existing data. However, much of the gas-in-place is unlikely to contribute to future gas supply, for the most part because geological conditions make the gas extremely difficult to produce. The quantity of gas likely to be produced is a function of the price of the gas, the available technology, the associated costs of production, and a variety of other factors, such as institutional barriers, that will influence decisionmaking on production. Several organizations have attempted to estimate the size of the recoverable resource. Reports have been issued which describe the resource and designate the most favorable areas for production.[28] Production scenarios have also been established by further assuming drilling and development schedules. In general, the estimates of recoverable resources and future production are based on extrapolation of past production, for which there is a sizable amount of data due to the long production history of the shales. However, the production data are limited in important ways. Available production histories are for the most part limited to wells using traditional production technology, that is, "shooting" with explosives at wide well spacing. Also, these histories are affected by a variety of factors aside from the nature of the gas resource. These factors include differences in market conditions, well operating practices, production techniques, the use of workover treatments, and pipeline pressures.[29] Extrapolation of production data therefore should account for these variables, yet the lack of data and the complexity of the necessary analysis makes such an accounting quite difficult. None of the existing studies of recoverable resources have attempted such an accounting. Also, it is not clear to what extent the drilling represents a true unbiased sample of what might occur on undrilled acreage if the same production techniques were used. These problems with the available data are discussed later.

[28] Favorable areas are designated by State in DOE/METC reports 118-124 and on a play basis in the USGS report entitled, "Estimates of Unconventional Natural Gas Resources of Devonian Shale of the Appalachian Basin, " 1982.

[29] R. E. Zielinski and R. D. McIver, *Resource and Exploration Assessment of the Oil and Gas Potential in the Devonian Gas Shales of the Appalachian Basin,* U.S. Department of Energy, Morgantown Energy Technology Center Report DOE/DP/0053-1125.

## Methodologies and Results

As illustrated in table 46, several estimates of recoverable resources have been made. These include early estimates by the Office of Technology Assessment (OTA), Lewin & Associates, and the National Petroleum Council (NPC). Each estimator assumed economic and technologic parameters to establish estimates of recoverable resources in the Appalachian Basin. Both Lewin & Associates and the NPC extended their analysis to include annual production estimates or scenarios.

More recently, Pulle and Seskus of Science Applications, Inc. (SAI), Zielinski and McIver of Mound, and Lewin & Associates also estimated the recoverable resource in the Appalachian Basin. Pulle and Seskus[30] used past production

[30] C. V. Pulle and A. P. Seskus, "Quantitative Analysis of the Economically Recoverable Resource, " U.S. DOE-METC, 1981.

**Table 46.—Devonian Shale Recoverable Resource Estimates (TCF): Appalachian Basin**

| Organization | Year | Estimate | Conditions |
|---|---|---|---|
| Office of Technology Assessment | 1977 | 15-25 | After 15 to 20 years |
| | | 23-38 | After 30 to 50 years |
| | | | At $2 to $3/MCF (1976), current technology (borehole shooting or hydrofracturing), 150-acre spacing |
| Lewin & Associates | 1978-79 | 2-1o | Base case |
| | | 4-25 | Advanced case for prices between $1.75 to $4.50 |
| | | traditional - advanced | |
| National Petroleum Council | 1980 | 3.3 - 38.9 | For price levels between $2.50 to $9, 160-acre spacing |
| | | 15.3 - 49.9 | Technically producible |
| Pulle and Seskus (SAI) | 1981 | 17-23 | "Shot" wells, 160-acre spacing |
| Zielinski and McIver (Mound) | 1982 | 30-50 | For States of West Virginia, Ohio, and Kentucky only, "shot" wells, 160-acre spacing |
| Lewin & Associates | 1983 | 6.2-22.5 | Technically recoverable, for most promising formations in Ohio. Maximum represents 80-acre spacing, advanced technology |
| Lewin & Associates | 1984 | 19-44 | Technically recoverable, for most promising formations in West Virginia. Preliminary values |

SOURCE: ???

**data and Delphi estimation to compute a mean value of 20.2 TCF** for the recoverable Appalachian resource using explosive fracturing at 160-acre spacing. Zielinski and Mclver[31] utilized SAI data to estimate the recoverable resource, also based on explosive fracturing. They felt that sufficient data were not available to make a reliable estimate, but produced a preliminary estimate of 30 to 50 TCF for the minimum recoverable gas in West Virginia, Ohio, and Kentucky. The most recent estimation effort was performed by Lewin & Associates under contract to DOE's Morgantown Energy Technology Center (METC) and was an estimate of the technically recoverable reserves in the most favorable Devonian formations in Ohio and West Virginia (the estimates for West Virginia were published only in draft form at the time of this report).[32] To OTA's knowledge, this estimate is the only one currently available to use reservoir simulation. Using this simulation capability, the analysis explores the ramifications of alternative fracture technologies, well spacing, and well patterns on the size of the recoverable resource.

## Office of Technology Assessment[33]

The OTA report was published in 1977 and was the first study that attempted to evaluate the recoverable Devonian shale gas resource in the Appalachian Basin.

OTA established production estimates based on 15 to 20 years of production data from 490 wells in three productive areas of the Appalachian Basin. Wells from Cottageville and Clendenin, WV, and Perry County, KY, were grouped according to the quantity (high, medium, or low) of gas produced. Average production rates were calculated for both shot and fractured wells in each group and used to calculate the recoverable resource assuming a productive area of 16,300 square miles— 10 percent of the entire basin area of 163,000 square miles. A well spacing of 150 acres was assumed, yielding approximately 69,000 wells. The economics were determined using an after tax net present value (ATNPV) model, a discount rate of 10 percent, and a wellhead price for gas in the $2 to $3/MCF range (1976$).

The findings as reported by OTA are summarized below:

- The Devonian shale resource could be produced without developing new production equipment and techniques.
- The Brown shaless[34] (as they were called by OTA) could yield between 15 and 20 TCF during the first ıs to 20 years of production. After 30 to 50 years, cumulative production could reach 23 to 38 TCF.
- Because of the tremendous drilling effort and the time required to develop the-necessary pipeline infrastructure, as many as 20 years may be required before annual production reached 1 TCF.

A critical factor in OTA's analysis is the assumption that only 10 percent of the Appalachian Basin will prove to contain gas recoverable at the assumed price using conventional technology. This assumption is based on the general argument that past drilling has not been random, but instead has been skewed to the high-quality areas–a universal tendency in resource development—and also upon observations of the clustered nature of existing development, the considerable depths and/or thinness of the shales in some undeveloped portions of the basin, the poorly developed fracture systems in other undeveloped areas, and the lack of success of drilling in some of these areas. This assumption that much of the undeveloped acreage in the basin will not prove to be productive is undoubtedly correct **qualitatively,** but there appears little quantitative basis for the choice of 10 percent as the productive fraction; it is essentially an educated guess.

[31] R. E. Zielinski and R. D. Mclver, "Resource and Exploration Assessment of the Oil and Gas Potential in the Devonian Gas Shales of the Appalachian Basin, " 1982.

[32] V. A. Kuuskraa, et al., *Technically Recoverable Devonian Shale* Gas in Ohio, Lewin & Associates Report for Morgantown Energy Technology Center, July 1983; and V. A. Kuuskraa, et al., *Technically Recoverable Devonian Shale* Gas *in* West Virginia, Summary, 1984 (draft).

[33] Office of Technology Assessment, "Status Report of the Gas Potential From Devonian Shales of the Appalachian Basin, " 1977.

[34] Brown shales are generally younger than black shales and have more hydrocarbons in the organic material. The organics in the black shales are closer to elemental carbon. (V. Kuuskraa, 1982, "Unconventional Natural Gas," in *Advances in Energy Systems and Technology, vol. 3.)* Brown and black shales are commonly referred to jointly as black shales.

## Lewin & Associates I[35]

Lewin & Associates addressed the gas potential of Devonian shales in a series of 1978-79 reports entitled "Enhanced Recovery of Unconventional Gas." The purpose of the Devonian shale portion of the study was to estimate the economic potential of the resource, based on empirical data such as geology, reservoir performance, and costs.

The Lewin & Associates study evaluated gas recovery potential with respect to price for base and advanced cases. The parameters assumed for each case are listed in table 47. Economic analyses were performed to determine the economically recoverable resource at $1.75, $3.00, and $4.50/MCF (1977$) for both the base and advanced cases. The base case represents the development of areas with producing characteristics similar to areas under production today, using available small-scale hydraulic fracturing techniques with design fracture lengths of 100 to 200 ft. The advanced case added a mix of strategies to the base case to increase production and enlarge the size of the recoverable resource, including:

- extension drilling into deep shales, with improved stimulation (in eastern West Virginia and Pennsylvania);
- dual completion, i.e., stimulating two separate gas-bearing intervals from one well, with improved stimulation (in Ohio), to allow economical production of marginal prospects; and
- improved recovery through advanced stimulation technologies and closer well spacing (in eastern Kentucky and western West Virginia, the center of current production).

The evaluation was confined to the Appalachian Basin. Of the entire basin area of 210,000 square miles, only 62,000 square miles were considered as potential shale gas-bearing areas. The 62,000 square mile area was divided into 12 analytical areas based on similar geologic characteristics, drilling or production histories. Approximately 5,000 square miles of that area included already proven areas or sites of previous production, leaving 57,000 square miles as probable and possible gas-bearing areas.

Actual production data from several gas companies and 250 individual wells were collected and cumulative production decline curves established for each area. The production curves were adjusted for "play out," to compensate for the fact that fields tend to produce less as drilling

[35]Lewin & Associates, Inc., *Enhanced Recovery of Unconventional Gas,* U.S. Department of Energy reports HCP/T 2705-01, 02, and 03, 1978-79.

**Table 47.—Summary of Major Differences Between Lewin Base and Advanced Cases in Devonian Shale Analysis**

| Strategy item | Base case | Advanced case |
|---|---|---|
| ***Source characterization:*** | | |
| Eligible areas | Probable areas | Probable and possible areas |
| Dry hole rates | 20% | 10% |
| ***Technology:*** | | |
| Completions | Single | Dual where a low producer is underlain by other productive pay |
| Recovery efficiency per unit area | Current levels | Improved by 20 percent in higher producing areas |
| ***Economics:*** | | |
| Risk—reflected in discount rates[a] of | 21 '/0 | 160/0 |
| ***Development:*** | | |
| Start year for drilling | | |
| Probable area | 1978 | 1981 (R&D effect begins) |
| Possible area | 1987 | 1987 |
| Development pace | | |
| Probable area | 17 years to completion | 13 years to completion |
| Possible area | 17 years to completion | 15 years to completion |

aDiscount rates include a constant ROR based on 10 to 150/0 and an inflation adjustment of 6°/0

SOURCE: Lewin & Associates.

moves **into extension areas, and for stimulation technology improvement, to compensate** for the differences between the old explosive fracturing and hydraulic fracturing. The adjusted curves were then used to estimate 30-year cumulative recovery per well for each area. These estimates were then used in the analysis of the economic potential.

The economic analysis used a discounted cash flow model. Net cash flow was calculated by subtracting investment costs, operating costs, and all other allocated costs from the cash flow acquired from production revenues. The net cash flow for the 30 years of production for each well considered in the study was discounted to arrive at the net present value. The areas with a positive net present value were assumed to be developed in accordance with the timing schedule designated for each case.

The results of the economic evaluation are summarized in table 48. The base case estimates are quite pessimistic—at $4.50/MCF (1 977$), or $7/MCF (1 983$), a very high price in today's market, total recoverable resources are only 10.5 TCF. The somewhat more optimistic advanced case, which reaches 18 to 25 TCF at the same price, obtains most of its added recovery from the deep drilling and dual completions, with improved recovery in existing producing areas yielding only 2.1 TCF at this price.

An important consideration in this analysis is that Lewin considered there to be little difference in **per well** recovery efficiency between the base and advanced case, despite the more effective fracturing attainable in the advanced case. The major difference between the two cases is the more rapid drainage attainable with the improved stimulation technology, which greatly improves the economics of recovery and moves marginal areas into the "economically recoverable" range. The source of this interpretation is the belief at the time that the primary source of producible gas is the fracture porosity.[36] This was thought to imply that the recovery efficiency of even borehole shooting would be quite high, in the neighborhood of so percent, with little improvement obtainable from more effective fractures. It currently is believed, however, that much of the long-term well production is from the resorption of gas bound to the shale matrix, and that the actual recovery efficiency of borehole shooting is only a few percent. Lewin's new work, described later in this section, folds this new understanding of the source of recoverable Devonian shale gas into its analysis (see the discussion of "Lewin & Associates 11"). An important implication of this understanding is that improved fracturing should increase ultimate recovery, not just accelerate production.

**Table 48.- Lewin & Associates: Results of Economic Analysis, Summary Table**

| Price, 1977$ (1983$) | Economically recoverable: Base case | Economically recoverable: Advanced case |
|---|---|---|
| $1.75/MCF ($2.75/MCF) . . . . | 2 TCF | 5 TCF |
| $3.00/McF ($4.70/MCF) . . . . | 8 TCF | 16 TCF |
| $4.50/MCF ($7.00/MCF) . . . . | 10.5 TCF | 18 to 25 TCF[b] |

aCurrent proved reserves are 1 TCF and the following estimates represent additions to reserves.
bThe range reflects the geologic uncertainty with regard to natural fracture intensity.

SOURCE: Lewin & Associates.

## National Petroleum Counci1[37]

The NPC also estimated the quantity of producible gas in the Appalachian Basin for different levels of technology and price. Three levels of technology were considered in the analysis: traditional (borehole shooting), conventional (conventional hydraulic fracturing), and advanced (unique fracturing techniques and deviated drilling). Advanced technology was assumed to double the production increase achievable from the use of conventional technology.[38] Conventional technology was assumed to increase production over traditional borehole shooting by O to 57 percent depending on the open flow rates of the wells.[39]

[36] In other words, it was thought that most of the recoverable gas was free gas stored in the natural fracture systems.

[37] National petroleum Cou nci l, *Unconventional Gas Sources—Devonian Shales, 1980.*

[38] This assumption *was* based on experiments performed i n Kanawha County, WV. Three advanced technology wells had production increases of 230 percent over wells stimulated by traditional shooting. Conventionally fractured wells showed 80 percent increases in production over traditionally shot wells.

[39] The advantages of fracturing over borehole shooting decline as the unstimulated flow rate increases; with flow rates above 300 MCF/D, fracturing was assumed to be no better than shooting.

The quantities of potential reserves for price levels between $2.50 and $9.00 (1979$) were estimated by performing discounted cash flow analysis for 10, **15,** and 20 percent after tax rates of return.

NPC's initial objective was to utilize existing production data to predictor extrapolate production in undeveloped areas. They intended to model the average well production decline of each county to the hyperbolic equation below:

$$\text{Production rate} = C_1\ (1 + C_3/C_2\ t)^{-1/C_3}$$

where $C_1$, $C_2$, and $C_3$, were empirically derived constants for that county. When the existing production data were fit to the equation, they discovered that all the decline curves, regardless of county, could be represented adequately with the use of 3 and 2.5 for $C_2$ and $C_3$, respectively. Therefore, apparently $C_1$ can serve as an index to characterize average production decline for each county. The relation of $C_1$ to cumulative production can be determined by integrating the hyperbolic equation over the appropriate time period. For example, 30-year cumulative production is equal to 4.43 Cl.

Several parameters, such as the various thickness estimates and depth, were evaluated for correlation with the $C_1$ values. The thickness of the black shale as determined by gamma-ray logs was the only parameter that correlated to $C_1$; it did so with a linear coefficient of 0.213, that is, the average county black shale thickness as determined by logging can be multiplied by 0.213 to obtain the $C_1$ value for each county. This value was used as the basis for the "traditional technology" case.

The results of the economic analysis are tabulated in table 49. The potential reserve is that portion of recoverable gas that is economically producible at a given price. The total producible gas is the total cumulative amount of in-place gas that can be produced over the wells' 30-year lifetimes, under the specified technological conditions, irrespective of price.

The major findings presented in the NPC report are listed below:

- Average well production can be modelled to a hyperbolic decline curve as represented by the equation below:

  $$\text{Production rate (MCF/D)} = C_1\ (1 + 5/6\ t)^{-2/5}$$

  $C_1$ is an index to characterize average production decline and is linearly related (linear coefficient of 0,213) to black shale thickness as determined by log data.
- The total producible gas using conventional technology is 37.4 TCF, which is approximately 30 percent of the 125 TCF estimated gas-in-place in drillable formations assuming the lower value of shale thickness based on gamma-ray well log data (see the discussion of the NPC estimates of gas-in-place earlier in this chapter), and about 4 percent of the 1,040 TCF gas-in-place using the visually determined thickness.
- The average price requirement for production of **37.4** TCF is $6.75/MMBtu (1979$)at 10 percent rate of return. Approximately 15 TCF can be produced at prices up to $3.50/ MMBtu.

## Pulle and Seskus (SAI)[40]

This analysis essentially extrapolates production data from 1,534 Devonian shale wells (with 10 years or more of production history) to full development of the Appalachian Basin's shales. The basin is divided into 10 subregions based on the thickness of the radioactive (black and brown)

[40] C. V. Pu lle and A. P. Seskus, Science Applications, Inc., *Quantitative Analysis of the Economically Recoverable Resource, DOE/MC/08216-l 57,* May 1981.

**Table 49.—Summary of Producible Gas Estimates Appalachian Basin (constant 1979 dollars and 10°/0 ROR)**

| | Cumulative potential reserves (TCF) v. price ($/MMBtu) | | | | | Total producible gas (TCF) |
|---|---|---|---|---|---|---|
| | 2.50 | 3.50 | 5.00 | 7.00 | 9.00 | |
| Traditional technology . . . . . . . . . . . . | 3.3 | 8.5 | 11.4 | 14.9 | 16.6 | 25.3 |
| Conventional technology . . . . . . . . . . . | 7.3 | 14.5 | 19.5 | 23.5 | 27.0 | 37.4 |
| Advanced technology . . . . . . . . . . . . . | 11.8 | 20.1 | 27.2 | 32.9 | 38.9 | 49.9 |

SOURCE: National Petroleum Council.

**shales, the** drilling depth of past production, and a measure of the thermal maturity of the shale cores that have been obtained. To obtain an estimate of the recoverable resource, wells are assumed to be drilled on 160-acre spacing, using explosive shooting for stimulation. Past production histories are used to estimate 30-year cumulative production for wells in half of the subregions; for the other subregions, production is estimated by combining the opinions of four experts in a Delphi procedure. The percentages of dry holes are estimated using the same Delphi procedure.

The estimated mean recoverable gas under the 160-acre spacing is 20.2 TCF, with an estimated 95 percent probability that the total lies between 17.06 and 23.34 TCF. However, the “95 percent probability” is a statistical value based on the assumption that the distribution implied by the historical data is a perfect reflection of future production from new wells. This seemingly high level of probability should not be treated too seriously. It does not account for errors introduced by the Delphi procedure, by changes over time in well “shooting” techniques, or by the possibility that past well locations were not random but instead represent some selection on the basis of relative prospects for success.

The analysis does not include an evaluation of the effect of price on well spacing, so it is not clear what gas price corresponds to the estimated 20,2 TCF of recoverable resources. On the other hand, the authors show how total recovery is likely to vary with well spacing; table 50 shows the variation of recoverable resources with assumed well spacing. This estimate is based on a theoretical model applied to only four wells, so the results should be treated as very tentative. Also, the estimated **recovery—and revenue—per** well for 10-acre spacing is only **one-fifth of the per well recovery and revenue** for 160-acre spacing. This implies that the gas price needed for economic recovery of the 67,9 TCF resource for 10-acre spacing will be five times the price needed for recovery at 160-acre spacing, all other things being equal. A countervailing factor, however, is that gathering costs are quite high in the Appalachian region, and closer well spacing and the resulting higher production levels per unit area would lower these costs.

**Table 50.—Effect of Spacing on the Devonian Shale Recoverable Resource**

| Spacing (acres) | Relative number of wells | Ratio of increase in resource | Total recoverable resource (TCF) |
|---|---|---|---|
| 160 . . . . . . . | 1 | 1.00 | 20.2 |
| 80 . . . . . . . | 2 | 1.68 | 34.0 |
| 40 . . . . . . . | 4 | 2.44 | 49.3 |
| 20 . . . . . . . | 8 | 3.10 | 63.0 |
| 10 . . . . . . . | 16 | 3.36 | 67.9 |

SOURCE: C. V. Pulle and A. P. Seskus, *Quantitative Analysis of the Economically Recoverable Resource,* US. Department of Energy Report DOE/MC/08216-157, May 1981.

## Mound Facility (Zielinski and Mclver)[41]

Zielinski and Mclver of the Monsanto Corp.’s Mound Facility have reviewed the NPC and SAI estimates of recoverable resources in the Appalachian Basin and, using the SAI data, derived an alternative, admittedly preliminary estimate of the recoverable resource in West Virginia, Ohio, and Kentucky.

Zielinski and Mclver’s review of the NPC estimates noted the following:

1. There are important numerical discrepancies between well production values reported by NPC as derived from their equations, and values actually calculated using these equations.
2. The NPC analysis derived a relationship for the initial production rate of a well by searching for correlations only with variables which have little to do with production, and picked a variable (gamma-ray log response) for the relationship only by default. Neither gamma-ray log response nor any of the other variables examined bear any relationship to the organic matter type or thermal maturation, both critical factors in determining gas potential.
3. The NPC found that a single equation could represent well production for the entire Ap-

41 R. E. Zielinski and R. J. Mclver, *Resource and Exploration* ***Assessment of the Oil and Gas Potential in the Devonian Gas Shales of the*** Appalachian Basin, Mound Facility Report to U.S. Department of Energy, DOE/DP/0053-1 125, undated.

palachian Basin. This may imply that, for the shot well technology used in most of the wells in the production histories, the fairly uniform porosity and permeability values of the shale dominate average gas production. This, in turn, implies to the reviewers that closer well spacing should significantly improve recovery if shooting is the method of stimulation.

The review of the SAI estimate noted the following:

1. SAI divided the basin into 10 subregions by evaluating four variables—radioactive shale thickness, drilling depth, stress ratio, and a measure of thermal alteration. Only the latter variable has any documented relationship to gas production, and this relationship is a limited one. Consequently, the extrapolation of production data in a subregion to undeveloped portions of that region may not be valid.
2. SAI assumed that well production in each subregion would be distributed lognormally, but the actual production data in the five subregions where production data was available did not tend to indicate a lognormal distribution.

Zielinski and Mclver also were concerned that neither the NPC nor the SAI estimates accounted for the effects of external influences–market forces, operating policy, production practices–on production, but instead implicitly assumed that past production was dependent only on the physical nature of the resource.

Based on the above concerns, Zielinski and Mclver's conclusion was that "the two . . . studies . . . do not form a sound foundation for the estimation of recoverable resource. "

Zielinski and Mclver have developed a preliminary estimate of recoverable resources in Ohio, Kentucky, and West Virginia based on the observation, from **SAI** production data, that the production per unit area of the developed portions of these States follow a clear pattern, **i.e.,** Kentucky's production tends towards $2.3 \times 10^{-3}$ TCF/mi$^2$, Ohio's towards $0.7 \times 10^{-3}$ TCF/mi$^2$, and West Virginia's towards $1.5 \times 10^{-3}$ TCF/mi$^2$. Extrapolating these values to prospective but undeveloped acreage yields a total recoverable resource of 30 to 50 TCF for the three States, for the same technology ("shooting") and well spacing (160 acres). This estimate is based on the assumption that different market conditions, production practices, etc., did not affect the State production averages, and also that past well siting was random. The authors consider the 30 to 50 TCF value to be a minimum for recoverable resources because improved stimulation technology, closer well spacing, or use of remote sensing techniques to improve well siting can individually or in combination increase total recovery as well as production rates. For example, Zielinski and Mclver predict that halving well spacing to 80 acres will essentially double the recoverable resource.

### Lewin & Associates II[42]

A recent estimate by Lewin & Associates makes use of the extensive data collection and analysis effort of DOE's Eastern Gas Shales Project, e.g., the geochemical analyses of Mound, and combines this with reservoir simulation to estimate the **technically recoverable gas resource** of the Lower and Middle Huron Intervals of the Ohio Devonian shale.

The Lower and Middle Huron Intervals represent only a portion of the resource base that potentially can be exploited; they contain about **50** TCF of gas-in-place, compared to an estimated gas-in-place of 390 TCF for Ohio and 2,579 TCF for the Appalachian Basin.[43] The Huron Intervals have been the traditional targets for past drilling in Ohio, and the great majority of available drilling data applies only to these intervals. The recovery potential of the remaining 340 TCF in Ohio is unknown. However, nearly half of the gas-in-place in the entire basin is considered by Mound to be undrillable because of surface constraints such as roads and towns, and thus the recoverable resource for the remainder of Ohio

[42] V.F. Kuuskraa, et al., Lewin & Associates, Inc., Technically *Recoverable Devonian Shale Gas in Ohio,* prepared for the Morgantown Energy Technology Center, U.S. Department of Energy, July 1983.
[43] From the Mound Study.

is unlikely to be as large, in relationship to its gas-in-place, as in the Huron Interval. Nevertheless, **the Lewin estimates should be recognized as representing only a limited portion of Ohio's Devonian shale gas potential, although the most prospective portion.**

Selected results of the Lewin analysis are shown in table 51. The results should be interpreted carefully because they refer to the expected physical results of a specified quantity of drilling and stimulation without regard to economic feasibility. In other words, they are comparable to the "technically recoverable" or "maximum producible" resources of other estimates. The results are particularly interesting, however, because Lewin's use of reservoir simulation provides for a more credible estimate of the effects of improved stimulation technologies and smaller well spacing. As shown in the table, both methods of improving gas recovery could be extremely successful in the Appalachian Basin. According to the report, 80-acre spacing has already started to supplant the more traditional 160-acre spacing in new drilling in the basin, Accordingly, the 8.7 to 10.5 TCF projected as the result of improved but relatively conventional technology at 160-acre spacing probably represents a pessimistic estimate of actual recoverable resources assuming high gas prices. This result has interesting implications for the future potential of Devonian shale gas in view of the limited portion of the total Appalachian resource represented by this analysis.

A more recent Lewin study, available in draft at the publication close of this report, estimates the technically recoverable Devonian shale resources in West Virginia. Table 52 summarizes the results, which apply to the Huron, Rhinestreet, and Marcellus shale intervals. These intervals represent the most promising shale prospects in the State, although only 70 TCF out of a total of 125 TCF of gas-in-place for the intervals was actually appraised. Insufficient reservoir data were available for the nonappraised portions of these intervals. In addition, hundreds of TCF exist in lower quality shale formations that may be developable at some point, but not with simple extensions of today's technology.

The results of the West Virginia assessment are even more optimistic than the Ohio results, given the estimated 25.4 to 32.7 TCF technically recoverable resource based on improved but readily attainable technology and 160-acre spacing. Coupled with the probability that Kentucky will prove to have recoverable resources somewhere in-between those of Ohio and West Virginia,[44] the Lewin results imply that the Devonian shale recoverable resource is considerably greater than imagined by all of the previous estimates reviewed herein.

[44] Vello Kuuskraa, Lewin & Associates, Inc., personal communication, 1984.

**Table 51.—Results of Lewin Assessment of Technically Recoverable Gas in Ohio, by Stimulation Method After 40 Years**

| | |
|---|---|
| I. Present technology, 160-acre spacing | |
| • Borehole shooting | 6.2 TCF |
| II. Improved but readily attainable technology, 160-acre spacing: | |
| • Small radial stimulation (30 ft radius) | 8.7 TCF |
| • Small vertical fracture (150 ft wings) | 10.5 TCF |
| III. Advanced technology, speculative, 160-acre spacing: | |
| • Large radial stimulation (60 ft radius) | 10.2 TCF |
| • Large vertical fracture (600 ft wings) | 15.2 TCF |
| • Large vertical fracture, 80-acre spacing (600 ft wings) | 21.0 TCF |
| IV. Changed well patterns (3 to 1 rectangle, taking account of permeability anisotropy) with improved or advanced technology: yields added recovery of 5 to 10 percent/well. | |

SOURCE: V. A. Kuuskraa, et al., *Technically Recoverable Devonian Shale Gas in Ohio,* Lewin & Associates Report for Morgantown Energy Technology Center, July 1983.

**Table 52.-Results of Lewin Assessment of Technically Recoverable Gas in West Virginia, by Stimulation Method After 40 Years**

| | |
|---|---|
| I. Present technology, 160-acre spacing: | |
| • Borehole shooting | 19.1 TCF |
| II. Improved but readily attainable technology, 160-acre spacing: | |
| • Small radial stimulation (30 ft radius) | 25.4 TCF |
| • Small vertical fracture (150 ft wings) | 32.7 TCF |
| III. Advanced technology, speculative: | |
| • Large vertical fracture (600 ft wings) | 88.4 TCF |

SOURCE: V. A. Kuuskraa, et al., *Technically Recoverable Devonian Shale Gas in West Virginia,* Summary, 1984 (draft).

## Estimates Comparison and Uncertainties

OTA's examination of the several estimates of Devonian shale recoverable resources established some important concerns:

First, with the exception of the latest Lewin & Associates reports on Ohio and West Virginia, the attributes of advanced recovery technologies were described vaguely, and a reservoir simulation model that could predict the effect of longer fractures or other attributes of advanced technologies was not available. Consequently, estimates of the effects of advanced recovery technologies on recoverable resources should be considered at best either "educated guesses" or extrapolations based on quite limited evidence.

Second, several of the estimates extrapolate available data on existing production to the entire Appalachian Basin by using methods that rely on guesswork, on arguable assumptions, or on apparent relationships with variables that do not seem likely to be strongly related to resource recovery potential. For example, the early OTA study did not formally relate well production to measurable physical attributes of the areas under development, presumably because there were inadequate data. Instead, the study assumed that 10 percent of the basin will be productive in the same manner as the area now under production, and that the remainder of the basin will be unproductive; the choice of 10 percent was not explained, but is essentially an "educated guess." Both the Pulle and Seskus and the NPC estimates relied on predictive variables—in NPC's case, shale thickness as measured by gamma-ray logs—which seem likely to be only limited predictors of gas recovery. The Zielinski and Mclver estimate for West Virginia, Ohio, and Kentucky, admittedly a preliminary, crude attempt, is based on the assumption that the existing wells, used for extrapolation, were randomly sited, so that their production would be representative of what would occur in the untested portions of the shale area. This type of assumption is more tenable in the Appalachian Basin than it would be elsewhere because sophisticated exploration techniques were not used to site the existing wells, the haphazard availability of land for drilling may have interfered with pattern drilling, and other factors. In our view, however, the information gained by earlier drilling is certain to have directed subsequent drilling to better-than-average prospects, and the direct extrapolation used in this study will tend to lead to an overestimate of the resource recoverable by borehole shooting.

Third, only a very small part of the Devonian shale has been tested by drilling, and consequently the available studies focus on the resources recoverable from the producing shale intervals, or those closely resembling them, i.e., those with well-developed natural fracture systems. Much of the gas-in-place exists in intervals which are not currently productive. For the most part, the large portion of this gas probably could not be produced with current technologies and prices. However, it may be possible to economically recover much of this gas with new technology, especially at higher prices. The existing studies cannot account for this possibility, and probably there is no credible way at present to determine the true potential of these intervals. Nevertheless, it must be made clear that the existing estimates of the Devonian shale resource potential do not include this speculative portion of the resource, and that there is at least the possibility that, with further technology development, the gas ultimately recoverable from the Devonian shales may be considerably larger than currently estimated.

Fourth, all of the estimates may suffer from the problem that past production has been influenced by the market and by other external influences on production. The studies all implicitly assume either that the resource characteristics are dominant in determining production characteristics, or else that any external influences on production will remain essentially unchanged during the period of development of the resource. Zielinski and Mclver have noted that these production influences might have affected the ultimate recovery of past wells, and should be taken account of when extrapolating to future production.

Comparison of the resource estimates of the various studies is made difficult by the first problem, the lack of clearly defined criteria for "advanced technologies, " and also by differences in

**assumed gas prices and study areas. However, relatively clear comparisons can be made of the resources recoverable by traditional borehole shooting. Table 53 compares the resource estimates of six studies for borehole shooting at 150- to 160-acre spacing and, for three of the studies, at prices moderately higher than current market prices** for new gas. The estimates of Pulle and Seskus, Zielinski and Mclver, and the recent Lewin study do not specify prices and are more in the nature of "technically recoverable gas. " They are best compared to the NPC "total producible" resource of 25.3 TCF and the 1977 Lewin estimate of 10.5 TCF for gas prices of $4.50/MCF ($7.00/MCF [1983$]); the latter should be close to a "technically recoverable" limit because of the rapidly diminishing returns for further price increases apparent in the Lewin analysis.

Because there has been extensive experience with borehole shooting, the estimates for recoverable resources using this technology should be the most reliable. There are serious differences among the estimates in table 53, however, and we believe these differences reflect some of our concerns with the individual studies. The Zielinski and Mclver estimate, which should be considered optimistic because it assumed that siting of past wells was random and therefore that their production experience would be representative of undrilled acreage, is in fact the highest of the estimates of technically recoverable gas. The 1977 OTA estimate is not based on a geological evaluation of the prospects of the undeveloped portion of the basin, and probably should be downplayed; it is, in fact, at considerable variance with the NPC and early Lewin estimates, which are more pessimistic. On the other hand, the early Lewin estimates also appear to be considerably more pessimistic than the recent Lewin estimates for Ohio and West Virginia; it seems likely that a new Lewin estimate of the Appalachian gas recoverable at about $4.70/MCF (1983$) would be considerably higher than the 8 TCF predicted by the early study. The difference between the early and more recent Lewin studies is emphasized by the recognition that the early study includes some hydraulic fracturing in its recoverable resource estimate; presumably, its estimate for the resource recoverable with borehole shooting only would have been even lower than 8 TCF.

In conclusion, OTA's best resolution of existing resource studies is that the Devonian resource ultimately recoverable with borehole shooting at 160-acre spacing and gas priced at $4 to $5/MCF (1983$) is at least 10 TCF and, based on the implications of the recent Lewin work, most probably is somewhat higher. Ultimately, if the Lewin analyses prove to be substantially correct, about 30 to 50 TCF may be recovered with this technology and spacing at very high prices. These are extremely conservative estimates of the actual gas potential of the Appalachian Basin, however, because neither the technology assumption nor the spacing assumption are realistic. Many producers in the basin have begun to use hydraulic fracturing, which increases ultimate recovery per well, and well spacing in the less permeable areas has begun to be decreased to 80 acres, which improves recovery per section. With borehole shooting as the "baseline" technology, halving

**Table 53.—Comparison of Estimated Appalachian Devonian Shale Resources Recoverable With Borehole Shooting, Well Spacing of 150 to 160 Acres**

| Study (data) | Gas price ($/MCF) study date (1983)[a] | Recoverable resource (TCF) | Total producible (TCF) |
|---|---|---|---|
| OTA (1976) | $2 to $3 ($3.03 to $4.95) | 23 | NA |
| NPC (1979) | $3.50 ($4.70) | 8.5 | 25.3 |
| Lewin I (1977) | $3000 ($4.68) | 8[b] | 10.5+ |
| Pulle and Seskus (1981) | None | | 17-23 |
| Zielinski and Mclver (1982) (West Virginia, Ohio, Kentucky) | None | | 30-50 |
| Lewin II (1983) (portions of Ohio and West Virginia only) | None | | 25.3 |

aThe 1983 gas price is obtained by applying the GNP Price Deflators published by the Bureau of Economic Analysis, Department of Commerce.
bIncludes hydraulic fracturing as well as borehole shooting.

SOURCE: Office of Technology Assessment.

the spacing seems likely to yield at least a 70-percent increase in recoverable resources, primarily because the area of influence of each well is smallest with this technology and thus the additional wells will interfere least with the adjacent wells. The **incremental benefit of reduced spacing will decrease for** recovery technologies that contact more of the formation because of interference between adjoining wells; however, Lewin estimated that halving the spacing will still add 40 percent to the recoverable resource in Ohio **even when the baseline technology achieves 600-ft fractures, which should maximize interference between wells.**

The use of conventional hydraulic fracturing and more advanced stimulation also can greatly increase the recoverable resource. The N PC estimates that conventional fracturing will yield a 50- to 70-percent increase in recovery over borehole shooting. They project an additional 40-percent increase over the conventional fracturing with the more advanced stimulation techniques, but this estimate is based on very limited experience. The recent Lewin study estimates that a stimulation achieving 600-ft fractures can more than double the recoverable resource over that obtainable with borehole shooting, and that a combination of this technology with 80-acre spacing can more than triple the resource.

These estimates imply that the recoverable resource in the Appalachian Devonian shales may prove to be quite large, perhaps 80 or 100 TCF or *even* higher with high gas prices and substantial improvements in recovery technology. **However, the current limited capability in reservoir simulation and our limited geologic understanding imply that estimates of recoverable resources using advanced technology should be viewed as having quite high uncertainty.**

Finally, as noted previously, none of the estimates consider the possibility of producing from shale intervals that do not contain well-developed natural fracture networks. This portion of the shale is a highly speculative resource, and its gas-in-place may never become recoverable. **Never**theless, it does present some potential for future recovery.

## Annual Production Estimates

Annual production estimates may be calculated by estimating the number of wells to be drilled and postulating a drilling schedule. The number of wells drilled is determined by the area considered to be drillable and the well spacing assumed. The larger the well spacing, the fewer the number of wells that may be drilled in a given area. The USGS argues that drainage patterns of Devonian shale wells are too variable to assume a constant spacing.

Lewin & Associates determined 1990 production estimates based on an available acreage of 57,000 square miles, a well spacing of 150 acres per well and the drilling and development schedules outlined for the base and advanced technology cases. The resulting estimates are shown in table 54.

Annual production and additions to reserves were also calculated in the NPC study. The number of wells drilled were constrained by an available acreage of 62,000 square miles, a well spacing of 160 acres per well and "low" and "high" drilling schedules. The low scenario assumed there would be initially 12 rigs drilling in Devonian shale in 1980, and a 12-percent increase each year thereafter. The high scenario assumed 15 rigs were active in 1980, with 15 rigs added each year through 2000. All rigs were assumed to drill 35 productive wells per year. The results of this analysis are included in table 55. As shown in the table, the high scenario depends on extremely high gas prices into the 1990s. Even with advanced technology, the year 2000 production rate of 1.35 TCF/yr requires gas prices above $10.00/MCF (1983$).

It is not clear whether or not the annual production estimates projected by the NPC and Lewin accounted for some important factors that can influence the rate at which the resource is developed. The effects of these factors are not readily quantifiable, but they can be used to qualify the production potential estimates.

One factor that definitely will affect the *pro*duction rate is the availability of adequate leases for exploration and drilling. In fact, in most ac-

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**Table 54.—Lewin & Associates Results for Annual Production Estimates**

| Price, 1977$ (1983$) ($/MCF) | Production rates (TCF/yr) Base case | Advanced case |
|---|---|---|
| 1.75 (2.75) | Peak 0.1 in 1990 declines thereafter | Peak 0.3 in 1990 declines thereafter |
| 3.00 (4.70) | Peak 0.3 in 1990 gradual decline thereafter | 0.6 in 1990, hold to 1995 declines thereafter |
| 4.50 (7.00) | Remains constant at 0.3 through 2000 | Increases to 0.7 to 0.9 in 1990 |

SOURCE: Lewin &Associates, Inc., Enhanced *Recovery of Unconventional Gas,* U.S. Department of Energy Report HCP/T2705-01, 02, and 03, 1978-79.

**Table 55.—Potential Incremental Supply of Devonian Shale Gas In the Appalachian Basin: NPC High Growth Drilling Schedule (production and reserve volumes [BCF] and price [$/MMBtu]) (constant 1979 dollars)**

| | 1980 | 1985 | 1990 | 1995 | 2000 |
|---|---|---|---|---|---|
| Annual productive wells drilled | 770 | 3,400 | 6,000 | 8,650 | 11,300 |
| Cumulative wells | 770 | 12,500 | 37,300 | 75,300 | 126,400 |
| Traditional technology: | | | | | |
| Annual production rate | 15 | 190 | 430 | 620 | 690 |
| Annual reserve additions | 200 | 890 | 1,250 | 1,110 | 720 |
| Cumulative additions | 200 | 3,300 | 8,800 | 14,300 | 18,400 |
| Incremental price at 10°/0 ROR | <2.50 | <2.50 | <5.00 | <7.00 | <12.00 |
| Conventional technology: | | | | | |
| Annual production rate | 17 | 220 | 550 | 865 | 1,005 |
| Annual reserve additions | 240 | 1,040 | 1,660 | 1,690 | 1,140 |
| Cumulative additions | 240 | 3,800 | 11,000 | 19,600 | 26,100 |
| Incremental price at 10°/0 ROR | <2.50 | <2.50 | <3.50 | <7.00 | <9.00 |
| Advanced technology: | | | | | |
| Annual production rate | 21 | 270 | 700 | 1,110 | 1,355 |
| Annual reserve additions | 290 | 1,290 | 2,030 | 2,170 | 1,600 |
| Cumulative additions | 290 | 4,800 | 14,000 | 25,100 | 34,500 |
| Incremental price at 10°/0 ROR | <2.50 | <2.50 | <3.50 | <5.00 | <9.00 |

SOURCE: National Petroleum Council.

tive **areas of Devonian shale drilling, perhaps 95 percent of all wells drilled are located on the basis of the availability of land. Most of the Devonian shale in the Appalachian Basin occurs** in the **older,** more populated areas, which over the years have been divided into **small tracts (by oil industry standards). Building an exploration** block of any size is difficult and expensive with many title problems. Also, a trend towards short-term leases of 1 year or less has made establishing an orderly exploration program difficult. Some States also have no well spacing requirements, making any tract capable of holding a potential drilling rig a drill site. **As a** result, a good well may be jeopardized by other wells that are placed too close to it.

The type of operators in the Devonian shale will also influence the development of the resource. The major oil companies have not invested in Devonian shale wells, due principally to land problems and poor well performance. The majority of operators are small companies financed by drilling funds or direct investment groups. Although these small operators can move swiftly into "hot" acreage, their cash flows are generally not sufficient to allow much exploration. As a result, many wells are drilled with little regard to geological conditions. A lack of funds could also inhibit the use of costly yet more effective evaluation and stimulation techniques, thereby reducing the quantity of gas ultimately recovered,

Aside from these uncertainties, and the obvious uncertainty introduced by our inability to project future economic and market conditions such as gas prices, demand, and availability of capital, production projections share most of the uncertainties associated with the estimates of recoverable resources discussed previously in this chapter. Of particular interest are uncertainties in the effects of improved stimulation technologies, since increases in fracture areas will affect production rates as well as total cumulative production. Consequently, production projections assuming the use of advanced technologies should be considered substantially more uncertain than projections assuming explosive fracturing. In the latter case, extrapolating from historic production data should be an acceptable procedure for projecting future production, although our lack of data on production practices and other factors that might have influenced past production rates requires that a substantial error band be placed around the results.

Production levels of about 1.0 TCF by the year 2000 would seem to be readily supported by the available studies: the 1977 OTA study concluded that 1.0 TCF/yr could be achieved 20 years after commencing an intensive drilling program, assuming relatively moderate prices; the first Lewin study projected a maximum production rate of 0,9 TCF/yr in 1990, with advanced technology and $4.50/MCF gas (1 977$) ($7.00/MCF [1983$]); and the NPC study projected a 1.0 TCF/yr production rate in 2000 using available technology, although admittedly at a very high price ($9.00/MCF [1979$]). However, high production levels of Devonian shale gas in the Appalachian Basin using currently available or moderately improved technology implies a massive expansion of drilling in an area where such an expansion is institutionally and physically difficult. Also, the production levels in the various studies were derived by assuming arbitrary drilling levels and extrapolating production data from quite limited areas to the basin as a whole. On the other hand, the recent Lewin work in Ohio and West Virginia implies that gas recovery (and production rates) per section can be increased substantially with reduced spacing, tailoring of drilling patterns to permeability anisotropy, and improved fracturing. Increased recovery per section could allow a more rapid expansion of production by easing problems of pipeline construction and land assemblage. Consequently, if gas market conditions in the Northeast improve very soon, institutional barriers to production are reduced or overcome, and exploration and production technology advances are achieved, OTA considers a production rate of 1.0 to 1.5 TCF/yr from the Appalachian Devonian shales by the year 2000 to be quite plausible. Achievement of the prerequisite conditions in the short time span involved is, however, still somewhat optimistic.

Chapter 10

# Coalbed Methane

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# Chapter 10
# Coalbed Methane

## INTRODUCTION

Methane in coal seams traditionally has been viewed as a hazardous waste product of the mining operation, rather than an energy resource in its own right. In fact, gas in a coal seam only contains 1 to 2 percent of the energy capacity of the coal itself. As a consequence, an estimated 217 thousand cubic feet per day (MCF/D) or 80 billion cubic feet per year (BCF/yr) of methane is vented to the atmosphere from U.S. mines,[1] without thought of recovery, to increase mine safety. The search for additional natural gas resources in the 1970s fostered an interest in economically recovering this "wasted" gas. By removing this gas before mining begins and either using it on site or selling it to the natural gas market, energy conservation could be combined with increased mine safety. In addition, it was realized that a potentially large gas resource lies trapped in seams of coal that will likely never be mined because of their depth or physical characteristics.

[1]V. A. Kuuskraa and R. F. Meyer "Review of World Resources of Unconventional Gas," IIASA Conference on Conventional and Unconventional World Natural Gas Resources, Luxenburg, Austria, June 30-July 4, 1980.

Although it is widely acknowledged that the coal bed methane resource is large, early economic assessments suggested that it had little potential for economic recovery barring very high gas prices. More recent evidence from wells producing gas from coal seams at current prices suggests a more optimistic outlook is justified. It appears that in some areas with highly favorable geology, commercial volumes of gas are recoverable at current prices using existing technologies.

Current production efforts include nearly 100 producing wells drilled by various operators in Alabama's Black Warrior Basin, early efforts by Carnegie Natural Gas Co. and Equitable Gas Co. in Pennsylvania and West Virginia, a variety of wells in the San Juan Basin of New Mexico, and others.[2]

[2]J. L. Wingenroth, "Recent Developments in the Recovery of Methane From Coal Seams," Gas *Energy Review, vol.* 10, No. 9, September 1982, American Gas Association.

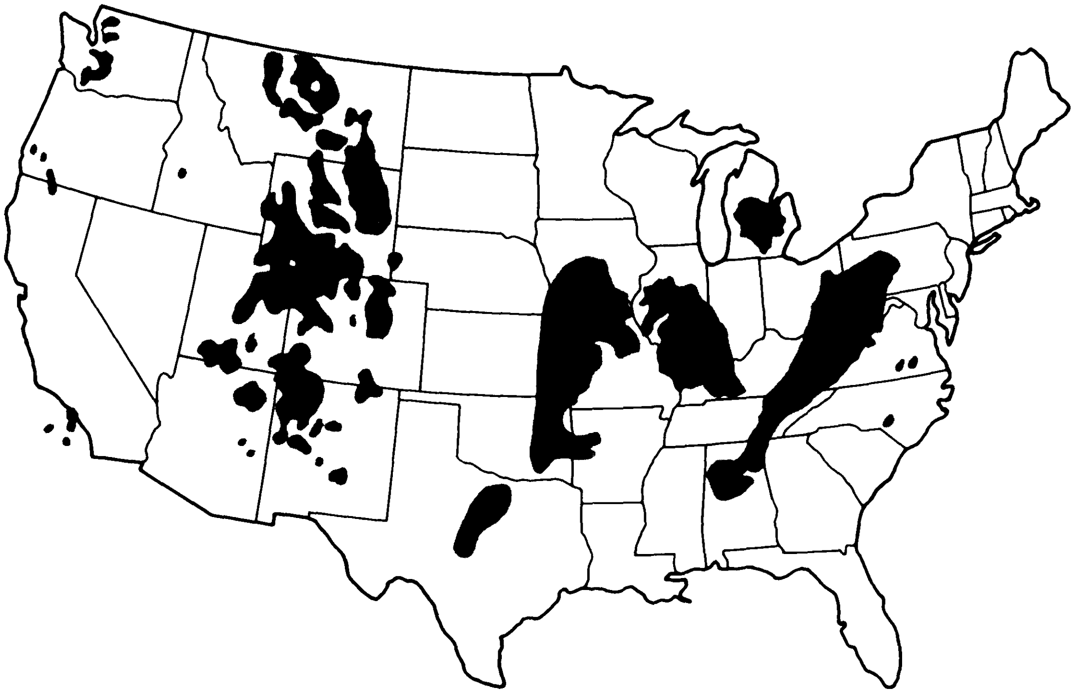
## CHARACTERISTICS OF THE COALBED METHANE RESOURCE BASE

Coalbed methane is defined as natural gas trapped in coal seams. The location of the Nation's coal resources and associated methane accumulations are depicted in figure 43. Approximately two-thirds of the resource is located in the West and Midwest and the remainder is located in the Appalachian Basin.

Methane forms as a byproduct of the coalification process.[3] With increasing temperatures, the rank (carbon content) of the coal increases, and larger volumes of methane and other volatile constituents are produced (fig. **44).** As volatiles are driven off by the increasing temperatures, the coal shrinks, giving rise to a pervasive natural fracture system called the "cleat." Although much of the generated gas migrates out of the formation, some remains in the coal seam adsorbed to the coal pore surfaces, and some is trapped in the pore spaces and fracture system by the reservoir pressure. In sharp contrast to conventional gas reservoirs, where essentially all of the gas is trapped in the pores and fractures, the adsorbed gas is the dominant source of coal bed methane and plays the major role in production. The volume of adsorbed gas appears to be a function of depth (pressure) and coal rank, as shown in figure 45. Nevertheless, given the vagaries of

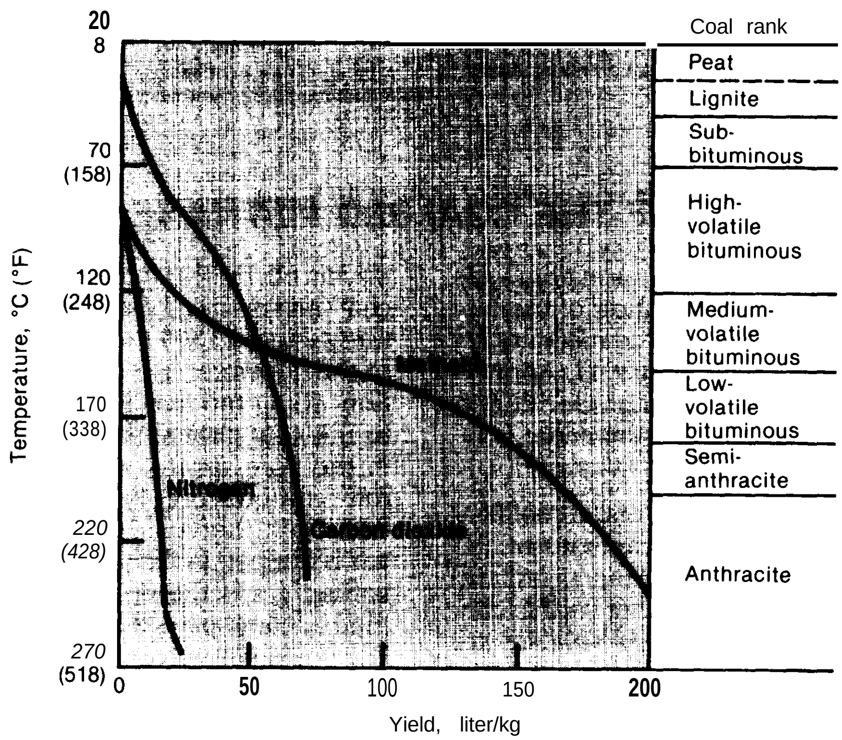
[3]Coalification: the formation of coal from organic-rich sediments, under intense heat and pressure.

**Figure 43.—U.S. Coal Regions**



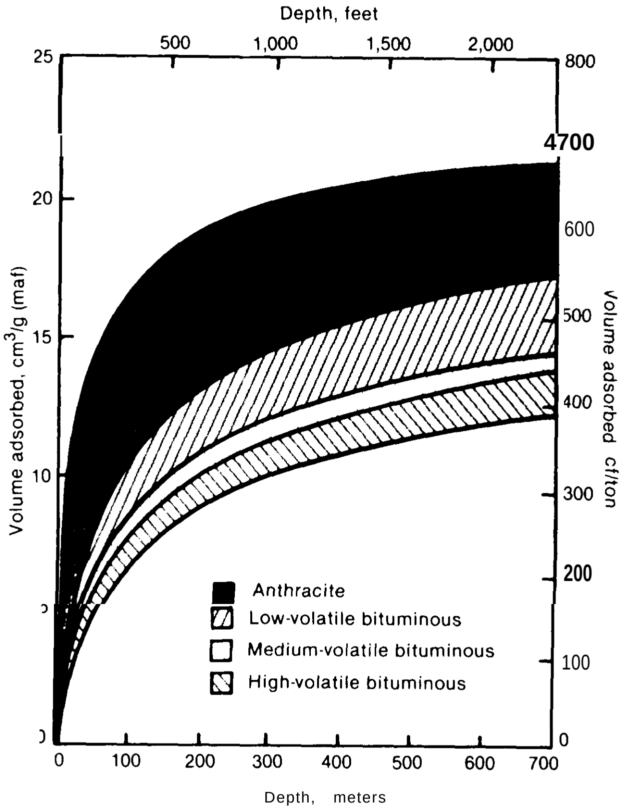
SOURCE: Department of Energy.

**Figure 44.-Variation of Gas Content by Rank, Temperature**




SOURCE: J. M. Hunt, *Petroleum Geochemistry and Geology* (San Francisco: W. H. Freeman & Co., 1978) (fig. 5-7, p. 165).

**Figure 45.—Variation of Adsorbed Gas by Rank**




SOURCES: A G Kim, “Estimating Methane Content of Bituminous Coalbeds From Adsorption Data,” BuMines RI 8245, 1977 c.f ; G. E. Eddy, C. T. Rightmure, and C. W. Bryer, “Relationship of Methane Content of Coal Rank and Depth, Theoretical vs Observed,” *SPE/DOE Unconventional Gas Recovery Symposium,* 10800, 1982

the geologic process, methane content in coal is highly variable from seam to seam and even within the same seam.

The quality of the gas present in coal seams is also somewhat variable, but generally is quite good. The heat of combustion ranges from 950 to 1,050 Btu per cubic foot. The gas has few impurities; carbon dioxide and water vapor are the primary undesirable components. Sulfur dioxide and hydrogen sulfide gases are absent even in the more sulfur rich coals.

Coal in itself is essentially impermeable. Bulk permeability of a coal seam depends on how well-developed the cleat is. Generally, there is a dominant system of vertical fractures, the so-called “face cleat, ” and a less developed system of vertical fractures perpendicular to the face cleat, the “butt cleat, ” the nature of the face cleat is critical to the coal’s production characteristics. The importance of the natural fracture system, together with the critical production role played by adsorbed gas, establishes a close parallel between coal seam methane and the Devonian shale gas resource.

Many coal seams contain water and thus the reservoir pressure is partially a hydrostatic pressure caused by groundwater. Although in some cases the water is the original product of the coal formation process, often the water infiltrates the coal from the surface or from overlying aquifers. The presence of this water has profound effects on gas production from the coal seams.

# GAS-IN-PLACE

Existing gas-in-place estimates are summarized in table 56. These range from a low of 68 TCF to a high of about 850 TCF. Most estimates are based on the U.S. coal resource; differences arise from varying assumptions of gas content (volume of gas per cubic foot or ton) of the coal and criteria for defining coal seams as good targets for recoverable gas.[4] Several of the most recent estimates are discussed in more detail below.

[4]These criteria are important because gas-in-place estimates generally consider only gas found in formations that contain potentially recoverable gas.

## Methodologies and Results

### National Petroleum Council, Gas Research Institute, and Kuuskraa and Meyer

**Among** the more recent studies, the estimates by the National Petroleum Council (NPC), the Gas Research Institute (GRI), and Kuuskraa and Meyer (KM) are very similar in methodology and in results. The estimated resource in place ranges from 398 TCF (NPC) to 550 TCF (KM).

All of these studies use the 1974 U.S. Geologic Survey’s (USGS) coal resource data—an estimate

**Table 56.—Coalbed Methane Resource Estimates**

| Study | Resource in place (TCF) |
|---|---|
| Department of Energy (1984) . . . . . . . | 68-395 |
| Kuuskraa and Meyer (1980) . . . . . . . . | 550 |
| National Petroleum Council (1980) . . | 398 |
| Gas Research Institute (1980) . . . . . . | 500 |
| Federal Energy Regulatory Commission (1978) . . . . . . . . . . . . . | 300-850 |
| Deul and Kim (1978) . . . . . . . . . . . . . . | 318-766 |
| Wise and Skillern (1978) ., . . . . . . . . . | 300-800 |
| TRW . . . . . . . . . . . . . . . . . . . . . . . . . . . | 72-860 |
| National Academy of Sciences (1976) . . . . . . . . . . . . . . . . . . . . . . . . | 300 |

SOURCE: Adapted from AGA Gas Energy Review, September 1982; and C. W. Byrer, T. H. Mroz, and G, L. Covatch, "Production Potential for Coalbed Methane in U.S. Basins," SPE/DOE/GRI Unconventional Gas Recovery Symposium, 12832, 1984.

of "minable" coal resources—as the basis for their estimates. The USGS assessment is broken down into identified and hypothetical resources at depths less than 3,000 ft and hypothetical resources at depths greater than 3,000 ft. The identified resources are further broken down by coal rank—anthracite, bituminous, subbituminous, and lignite. For the methane estimates, Kuuskraa and Meyer have subdivided the hypothetical resources by rank in approximately the same proportion as they occur in the identified resources.

The NPC, GRI, and KM analyses then multiply the coal resource by an assumed gas content to determine the gas resource in place. All assume that gas content varies with rank and depth. Assumptions are compared in table 57. Although the KM estimates disaggregate the gas content of coal to a greater extent than the GRI or NPC estimates, their assumed gas contents, averaged, are essentially the same as the GRI and NPC values. Consequently, the increased detail in their estimate does not contribute to a substantial difference in the calculated gas-in-place.

The **NPC estimate excludes all coal resources at depths less than 300 ft, assuming these coal seams contain essentially no recoverable gas.** The exclusion of shallow coals appears reasonable because the lower pressures may have allowed any gas originally contained in shallow seams to have escaped to the surface. However, the NPC also assumed that a full third of the identified and hypothetical coal resource between O and 3,000 ft occurs above 300 ft; also, the NPC apparently assumed that the bulk of this shallow coal is bituminous, with high gas content. Thus, the NPC analysis excludes from consideration a large percentage of the higher-gas-content coal. This conclusion appears to be the primary reason that the NPC estimates are 100 to 150 TCF lower than the GRI and KM estimates.[5] The exclusion appears overly pessimistic because it is the **lower rank**

[5] Although G RI also appears to exclude the coal resource at less than 300 ft from their gas-in-place calculations, in fact their total coal resource base is equal to the USGS coal resource base (3,968 X $10^9$ tons) from O to 6,000 ft.

**Table 57.-Coal Resource and Gas Content Assumptions**

| | Zero to 3,000 ft | | | | | Greater than 3,000 ft | | |
|---|---|---|---|---|---|---|---|---|
| | Kuuskraa & Meyer | | | | | | | |
| Coal rank | <1,000 | 1,000-3,000 | >3,000 | NPC | GRI | Kuuskraa & Meyer | NPC | GRI |
| ***A) Coal resource assumptions (billion short tons):*** | | | | | | | | |
| Anthracite (A) . . . . . . . . . . | 845 | 739 | 1,584 | 46 | 60 | | | |
| Bituminous (B) . . . . . . . . | | | | 1,001 | 1,300 | | | |
| A + B . . . . . . . . . . . . . | 845 | 739 | 1,584 | 1,047 | 1,360 | 176 | | |
| Subbituminous . . . . . . . . | 538 | 470 | 1,008 | 1,137 | 1,520 | 112 | | |
| Lignite . . . . . . . . . . . . . . . | 538 | 470 | 1,008 | 504 | 700 | 112 | | |
| Total . . . . . . . . . . . . . . | | | 3,600 | 2,688 | 3,580 | 400 | 388 | 388 |
| Total (all depths) . . . . | | | 4,000 | 3,076 | 3,968 | | | |
| ***B) Gas content assumptions-cubic ft/ton:*** | | | | | | | | |
| Anthracite and bituminous . . . . . . . . . | 150 | 250 | 197[a] | 200 | 200 | 500 | 200 | 200 |
| Subbituminous . . . . . . . . . | 60 | 100 | 79[a] | 80 | 80 | 200 | 200 | 200 |
| Lignite . . . . . . . . . . . . . . . | 30 | 50 | 39[a] | 40 | 40 | 100 | 200 | 200 |

[a] Weighted average.

SOURCE: Office of Technology Assessment.

(thus lower gas content) coals that tend to occur at shallower depths.

### Department of Energy (DOE) —Methane Recovery From Coalbeds Project

The DOE Coalbed Methane Basin analysis is the first attempt to estimate the gas-in-place on a basin-by-basin level. The DOE approach targets the most likely gas-producing coal seams in each coal-bearing basin. Wherever possible, they have established a range of gas contents for the targeted coals in each basin and calculated a gas-in-place. Data were obtained from a variety of producing wells and test wells. They have completed studies of 14 basins with an estimated total gas-in-place of 68 to 396 TCF. Results for the 14 basin analyses are summarized in table 58. The high end of this range is essentially compatible with earlier estimates; the low end is very conservative, being the product of lower estimates of both target area and gas content.

DOE appears to have made a number of subjective judgments in delimiting its target areas. For example, DOE selected for inclusion in the resource base only those coal seams with high reported gas contents, high rank, and thick cumulative sections, without setting any quantitative criteria for the selection. In addition, assessments of several basins have not been completed. Thus, its estimate is conservative in terms of total gas-in-place. Because it focused on formations that are the most likely to contain recoverable gas, however, the gas-in-place estimates may represent a valid basis for an estimate of the technically recoverable resource.

## Uncertainties

The wide range of gas content in coal seams, seen clearly in table 58, is the primary factor contributing to uncertainty in gas-in-place estimates. The range in the DOE gas-in-place estimates—over a factor of 5—may not be an unreasonable reflection of the true uncertainty at this time. The level of uncertainty will only be reduced as more data are obtained on gas content of specific coal seams. However, the impetus to obtain more data may only come as producers move to develop these resources.

The other major factor contributing to uncertainty is the lack of data on coal resources at depths greater than 3,000 ft. The USGS coal resource estimate is limited to potentially minable seams, and may substantially underestimate the gas-bearing resource. Very little information is available on the rank, reservoir characteristics,

**Table 58.— DOE Gas-In-Place Estimates**

| Basin | Gas contents (CF/ton) | Estimated total gas-in-place (TCF) | |
|---|---|---|---|
| | | Minimum | Maximum |
| ***Eastern:*** | | | |
| Northern Appalachian | 30-420 | | 61.0 |
| Central Appalachian | 125-400 | 10.0 | 48.0 |
| Illinois | 30-150 | 5.2 | 21.1 |
| Warrior | 7-600 | | 11.0 |
| Arkoma | 70-700 | 1.6 | 3.6 |
| Richmond | ND | 0.7 | 1.4 |
| ***Western:*** | | | |
| Piceance | 1 -410+ | 30.0 | 110.0 |
| Powder River | 1.45 | 5.9 | 39.4 |
| Greater Green River | 13-539 | 0.2 | 30.9 |
| San Juan | 20-135 + | 1.8 | 25.0 |
| Western Washington | 32-86 | 3.6 | 24.0 |
| Raton Mesa | 2-492 | 8.0 | 18.4 |
| Wind River | a | 0.5 | 2.2 |
| Uinta | 1-443 | 0.2 | 0.8 |
| Total | | 67.7 | 395.8 |

ND—no data
aAssumes deep coals will contain some gas

SOURCE. C. W Byrer, T H. Mroz, and G L Covatch, “ProductIon Potential for Coal bed Methane in U.S Basin s,” SPE/DOE/GRI Unconventional Gas Recovery Symposium, 12832, 1984 and gas content of the deep and unminable coals. Because deep coals are likely to be of higher rank and have higher gas content than shallower coals, b gas-in-place estimates that assign to the deep coals the same coal rank distribution found in the shallow coals may be too conservative. However, very low permeabilities, particularly in anthracites, may exclude some of these coals as sources of economically recoverable gas resources, absent significant advances in well stimulation technology.

‘Deeper coals are more likely to have been exposed to high temperatures, which in turn influence rank and gas content. See fig. 44.

To the extent that the deep coal seams are not considered to be viable targets for mining, many of the legal and institutional constraints to producing methane from minable coal seams will not be applicable to these deep seams. This may increase their attractiveness to gas producers. Refining the estimates of the deep gas resource, along with incorporating improved gas content data from the newly drilled basins, are the most important tasks remaining in establishing a more credible estimate of the coal bed methane gas-in-place.

# PRODUCTION METHODS AND TECHNOLOGY

## Production Methods

Producing coal seam methane is considerably different from producing natural gas in conventional reservoirs. Production rates in conventional reservoirs are primarily a function of permeability, whereas in coal seams, methane production is also dependent on the rate at which the adsorbed methane diffuses into the fracture network, or “cleat.” If the permeability of the coal’s fracture network is very low, then permeability will be the factor controlling production rates. However, when the fracture network is relatively permeable and is connected to the well bore, or when the fracture network is not well-developed (and thus the surface area for diffusion to take place is limited) production is more likely to be limited by the rate of diffusion of the adsorbed methane into the fracture network.

These different limiting factors have important implications for the probable effects of fracturing. If permeability is controlling, fracturing should increase production by enhancing the flow path from the fracture network to the wellbore. If diffusion is controlling, however, fracturing is unlikely to greatly affect production because it cannot add greatly to the surface area available for resorption, and any increased permeability it creates will not add to production.[7]

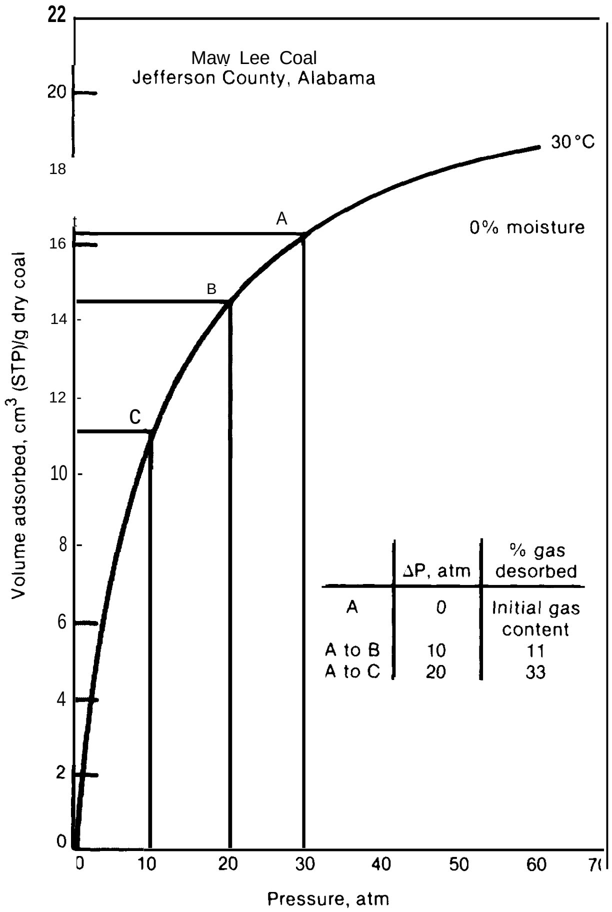
[7]Lewin & Associates, Inc., *Enhanced Recovery of Unconventional Gas, Volume ///: The Methodology,* U.S. Department of Energy report HCP/T2705-03, February 1979.

**It is necessary to reduce the pressure in the fracture systems in order for gas to desorb from the coal and be available for production.** Figure 46 shows how reducing the pressure will reduce the volume of gas adsorbed. The pressure/gas volume curve, which is typical of coal seams, is strongly nonlinear: a unit pressure drop has far less effect on resorption at high pressures than it does at low pressures. As a result of this nonlinearity, there may be little or no gas production until the pressure in the formation is reduced to the level where the rate of resorption per unit pressure drop begins to accelerate.

Because the reservoir pressure generally is a hydrostatic head associated with the groundwater in the coal seam, reducing the reservoir pressure means dewatering, i.e., pumping the water out of the seam. Water removal also increases the relative permeability of gas in the fracture network, allowing more gas to flow to the well bore. This also tends to reduce the pressure in the formation, further increasing the ability of gas to desorb from the coal,

As pumping the water from a well commences, the reservoir pressure is first reduced in the immediate vicinity of the wellbore, with the area of the pressure drop spreading overtime. The rate of gas production generally will increase with time as more and more area achieves the large pressure drop necessary to cause rapid resorption. This production increase with time is in

**Figure 46.— Methane Gas Adsorbed on Coal as a Function of Pressure**




SOURCE: S. C Way, et al , "Role of Hydrology in the Production of Methane From Coal Seams," Quarterly *Review of Methane From Coal Seams Technology, vol* 1, No. 2, August 1983, Gas Research Institute,

sharp contrast to the more normal production de**cline** experienced in conventional gas wells.[8]

This model of gas production from coal seams may not apply to single, isolated wells. In coals with highly permeable, interconnected fracture systems, the effect of pumping over time will draw the pressure down in small increments over a wide and expanding area with little change in the pressure distribution near the wells.[9] Because resorption is strongly nonlinear, favoring a large pressure drop, the areal extension of a moderate pressure drawdown is likely to yield little additional gas. The solution to this problem is to somehow bound the drainage area of the wells so that larger pressure drops occur over time. One method is to drill a closely spaced pattern of wells and pump them simultaneously, deliberately creating interference between adjacent wells. Such interference will effectively halt or bound the areal spread of pressure drop from a single well. This practice is in sharp contrast to normal practice in conventional gas fields, where close spacing and well interference are avoided because they reduce average recovery per well.

Figure 47 shows pressure drawdown curves for a group of three wells. The broken lines represent the pressure curves associated with each well **in isolation;** the solid lines are the actual pressure curves that result from the three well system, reflecting the interference effects of the wells on each other. Close spacing of wells allows more of the formation to achieve the sharply reduced pressures necessary for maximum resorption and production of gas. The advantage of closer spacing is particularly apparent when water can infiltrate the formation. Pumping from isolated wells may simply be unable to remove the water faster than it can infiltrate, and thus such pumping will not successfully dewater the formation and produce the gas; simultaneous pumping from a group of wells generally can "outrun" the infiltration. In a formation where water infiltration is a problem, the **rate** of pumping also becomes critically important, since a higher pumping rate may be necessary to outrun the infiltration and successfully draw down the pressure.

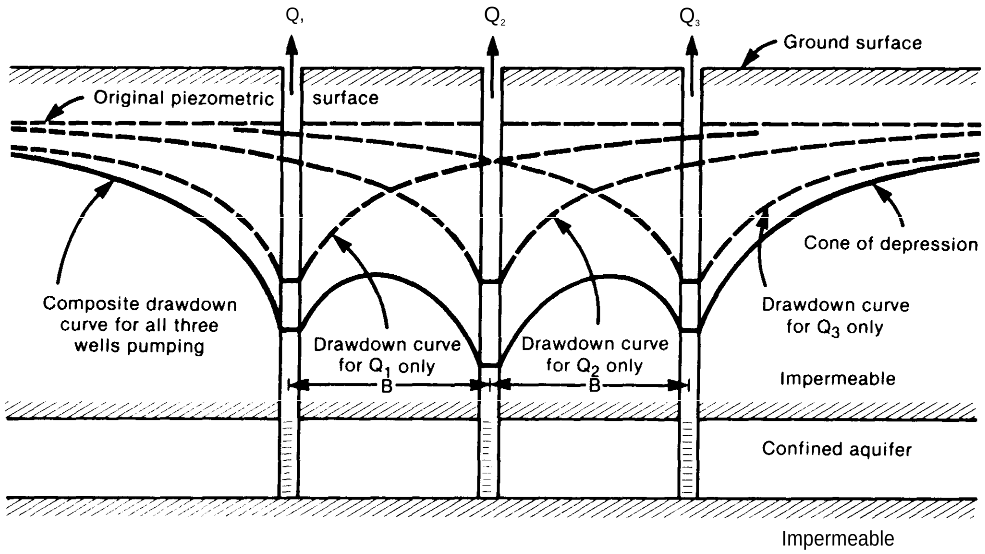
One well spacing pattern uses exterior wells to produce water and provide interference, while interior wells produce most of the gas.[10] Simulated production from this configuration predicts consistent high flow rates over a 20-year term, as shown in figure 48.

[8] S. C. Way, et al., "Role of Hydrology in the Production of Methane From Coal Seams," *Quarterly Review of Methane From Coal Seams Technology,* vol. 1, No, 2, August 1983, Gas Research Institute.

[9] "New Advances in Coalbed Methane, " Intercomp Resource Development & Engineering, Inc. (appears as app. C in K. L. Ancell, *Coal Degasification, An Unconventional Resource,* Dowdle Fairchild & Co., Inc., Houston, TX).

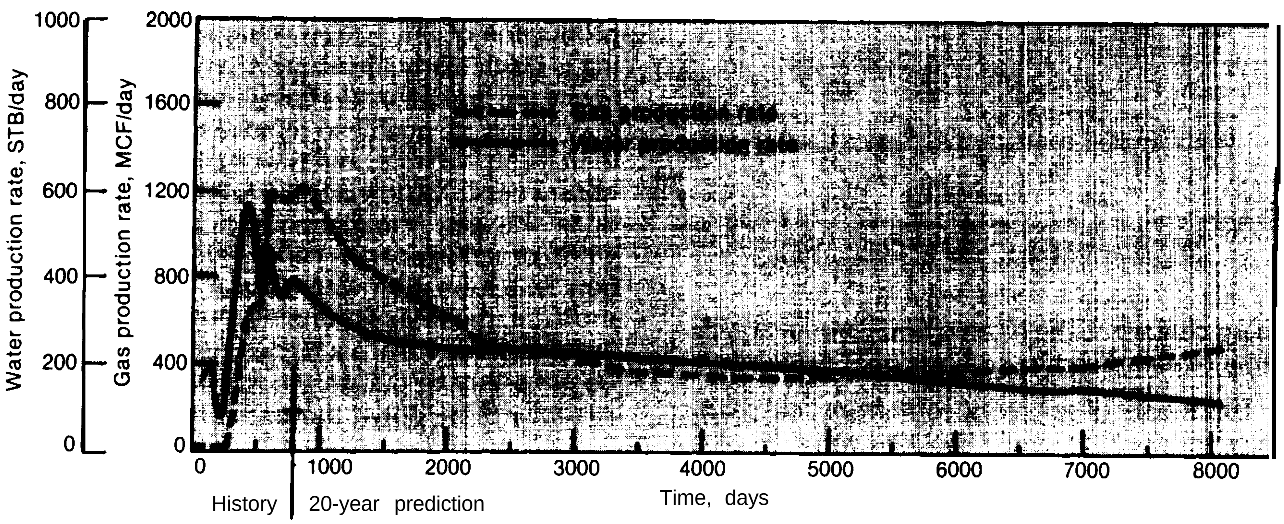
[10] Ibid.

**Figure 47.—Pressure Drawdown Curves for Three Wells in a Line**




SOURCE: S. C, Way, et al., "Role of Hydrology in the Production of Methane From Coal Seams," *Quarter/y Review of Methane From Coal Seams Technology, vol.* 1, No. 2, August 1983, Gas Research Institute.

**Figure 48.—20-Year Production Prediction for Gas and Water Production From a Well Pattern Designed to Allow Rapid Water Removal**




SOURCE: INTERCOMP Resource Development and Engineering, Inc.

## Technologies

Increasing production, at least from shallow wells, does not depend primarily on the development of new technologies. The primary target for improved technologies are the deep coal seams. There we need better reservoir characterization techniques. New drilling and completion techniques also are required in deep wells where drilling fluids or cements used for completions are likely to cause extensive formation damage. Stimulation technologies also have not been highly successful in the lower permeability deep coal seams.

### Drilling

Most current production of methane from both minable and unminable coalbeds uses vertical wells drilled through the coal seam. Major problems involve extensive formation damage induced by drilling fluids and by cements used to complete the holes. In shallower wells, air or water drilling and open hole completions[11] can counteract these problems. Improved production from multiple completions[12] and from deep coal seams where open hole completions may not be practical will require new technology developments. Current research programs sponsored by the Gas Research Institute are addressing these problems.

Another problem inherent in vertical drilling is the difficulty of intersecting the vertical fracture network, or face cleat. Well stimulation may be required to connect the wellbore with the natural fracture system and thus provide a pathway for gas to flow to the well. Another remedy is to slant or deviate the wells from the vertical to intersect the face cleats. Ideally, the well can be drilled parallel to the seam, as sketched in figure 49. This technology requires considerable improvement and cost reductions to be considered a realistic option for coal seam methane production. Keeping the wellbore in the coal seam is quite difficult, and drilling costs are significantly higher than for vertical wells. Dewatering deviated wells may also be a problem.

In minable coal seams, horizontal wells may be used. These wells usually are drilled from within the mine workings, perpendicular to the face cleat, and generally have high rates of gas drainage. The gas recovered from the boreholes is pumped through a separation unit to remove associated water before the gas is piped out of the mine.[13]

The main difficulty in drilling horizontal holes is keeping within the coal seam. Consolidated Coal Co. (Consol) has developed a mobile horizontal drilling system with special features for methane production. Three- to four-inch diameter holes may be drilled to lengths greater than 2,000 ft using a guidance system to keep the bit within the seam and methane is piped out through closed-loop plastic pipes.

Horizontal wells may partially escape dependence on the mining operation with a system that uses horizontal holes drilled radially from the bottom of a central vertical shaft. However, the expense of the shafts may dictate that the whole operation can succeed financially only if the shafts can be re-used later on for the mining operation; thus, it is not clear that this drilling system actually will sever the tie between mine and gas recovery operation. This method has not yet been tried in the United States.

### Stimulation

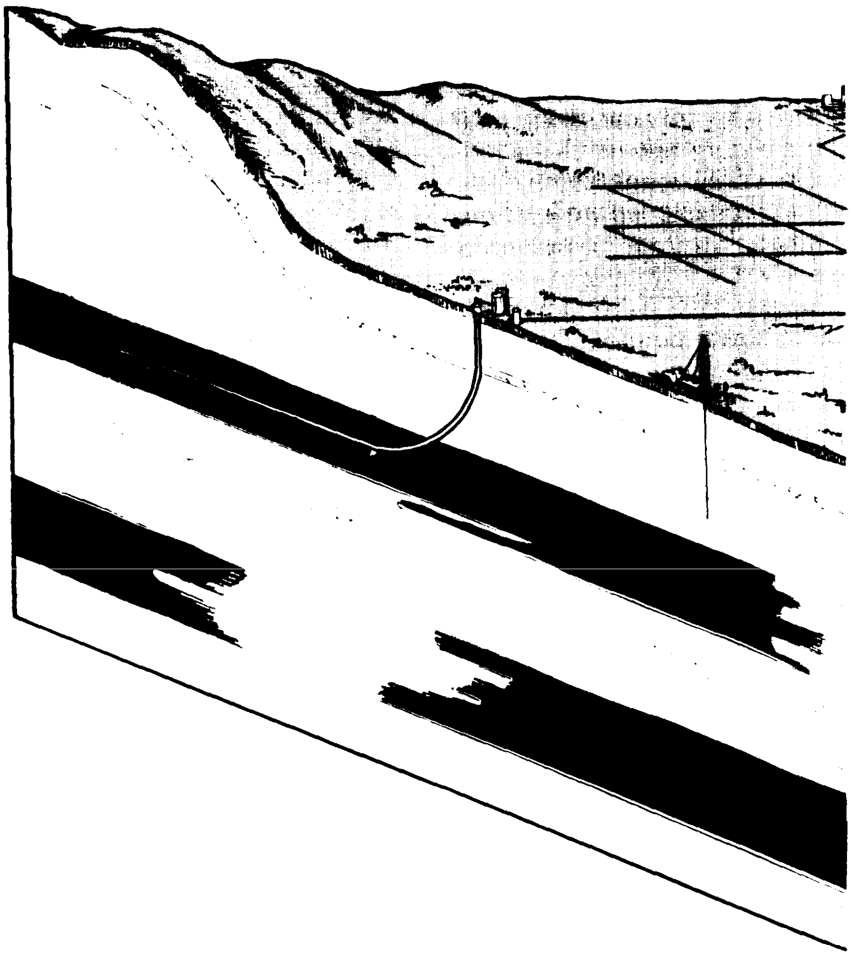
Where low permeabilities area problem, stimulation is used to increase the flow of gas to the well by increasing the area of the natural fracture system in contact with the wellbore. Hydraulic fracturing is the most common stimulation technique used. As with such treatments in the

[11] That is, completing the well by perforating the gas-bearing rock formation without first casing and cementing the wellbore in the vicinity of the formation.

[12] That is, producing from multiple seams with a single well.

[13] A major (but nontechnical) roadblock to substantial production of methane from these types of horizontal boreholes is that production may be dependent on the mine operation, If the mine were to close, the methane recovery operation might also be forced to cease. For example, at Kerr McGee's Choctau Mine in the Arkoma Basin, the coal seam methane production operation was completely set up, equipment installed, and approvals acquired when the mine was closed for lack of a coal market, Financing for a methane recovery project that is dependent on mine operation will tend to be difficult to obtain.

**Figure 49.—Deviated Drilling Into a Coal Seam**



SOURCE: Gas Research Institute.

Devonian shales, the most widely used fracturing fluids are nitrogen foam and water-based gel. A sized proppant may be included to hold open the newly formed fractures. The amount of each ingredient used **depends on the fracturing fluid pressure required, the coal seam thickness, the fracture length desired, and the cost. When the fluid injection is completed, the induced pressure is released and the well prepared for production.**

The effects of hydraulic fracturing may be entirely different in coals than in sandstone reservoirs. **An induced fracture** in sandstone will typically extend outward at substantial length from the well bore. Coal formation fractures are generally shorter and wider than sandstone fractures. The difference is attributed to the plasticity of the coal and dissipation of the compressional energy into the cleat system.[14]

Several problems may be encountered in stimulating coalbed wells. One is the tendency for proppant material to flow back into the well bore and create pump malfunctions during dewatering. Another problem is orienting the fracture to intersect rather than parallel the planes of the vertical fractures, or face cleat, in order to intersect as many fractures as possible. This may be difficult because the original stress field in the coal

[14]M. G. Doherty, "Methane From Coal Seams," International Conference on Small Energy Sources, Los Angeles, CA, Sept. 9-18, 1981.

clearly favored fracture directions parallel to the face cleat. A third problem, pertaining to minable seams, lies in containing the fracture within the seam. Some mine operators feel that fracturing can cause structural damage to the roof rock, increasing the potential for mine collapse. Ongoing work by the U.S. Bureau of Mines is attempting to evaluate the extent to which this concern is valid.[15]

[15] M. A. Trevits, M. E. Hanson, and V. L. Ward, "Methane Drainage: Identification and Evaluation of the Parameters Controlling Induced Fracture Geometry," SPE/DOE Unconventional Gas Recovery Symposium, May 16-18, 1982.

### Pumps

Water removal can in general be accomplished with existing pumping technologies, but the large amount of water that is produced during dewatering is a strain on pumping equipment and frequent maintenance is often required. pumps are also apt to become clogged with the coal fines remaining in the well after drilling. Dewatering deeper wells may require the development of larger capacity pumps. Nevertheless, solutions to these problems are more a matter of refinement of existing technology than radical innovation.

## RECOVERABLE RESOURCES AND PRODUCTION POTENTIAL

The coalbed methane resource base is large but, like the other unconventional resources, the recoverable portion is significantly less than the gas-in-place. Economic and technological conditions are the primary factors governing the amount of the resource that will contribute to future supply. Other factors, such as legal and environmental issues, also are likely to influence coal bed methane production, particularly from minable coal beds. Even without the hard-to-predict effects of these other issues, however, the uncertainty associated strictly with technical issues is high. The NPC, in describing its estimates for the recoverable gas resource, calls them "a qualified and educated guess," and "nothing more than an order-of-magnitude projection based on current information."[16] Although the scientific understanding of coal bed methane production has improved in the last 4 years, no estimates of the economically recoverable resource have been made since the 1981 GRI estimate.

[16] National Petroleum Council, *Unconventional Gas Sources: Coal Seams*, June 1980.

### Methodologies and Results

Estimates of the recoverable resource base have been made by the NPC (1 980), Kuuskraa and Meyer (1 980), and GRI (1 981). A variety of different economic and technology assumptions were used to obtain the estimates shown in table 59.

#### National Petroleum Council[17]

[n the NPC study, recoverable resources were calculated by identifying that portion of the resource that would yield sufficient production per well to cover the costs of an "average" well (with

[17] Ibid.

**Table 59.—Comparison of Recoverable Resource Estimates**

| | Technically or economically recoverable gas (TCF) | | | | Assumptions |
|---|---|---|---|---|---|
| KM | 40-60 | | | | 30-45°/0 recovery of target resource of 135 TCF, no price constraints, but recoverable resource limited to bituminous seams >3.5 ft thick, subbituminous seams >10 ft thick |
| NPC | $2.50 | $5.00 | $9.00 | | Production costs define minimum production levels, |
| | 5.0 | 25 | 45 | 10%\o ROR | which in turn define minimum economic thickness at 3 |
| | 2.5 | 20 | 38 | 150/0 ROR | MCFIDlft (bituminous), 1,2 MCF/D/ft and 0.6 MCF/D/ft |
| | 2,0 | 17 | 33 | 200/0 ROR | (subbituminous and lignite, respectively) Gas is used onsite, |
| GRI | $3.00 | $4.50 | $9.00 | Expert judgement | |
| | 10-30 | 15-40 | 30-60 | Existing-advanced technologies | |

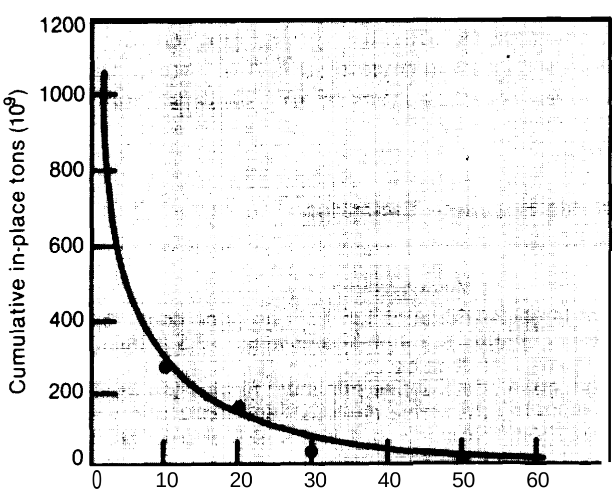
SOURCE Off Ice of Technology Assessment

a depth of 3,000 ft, 12-year well life, assumed 10 percent production decline rate, and 90 percent success rate). This was done by the following method:

1. Using county-by-county coal resource estimates, a distribution of the coal-in-place resource according to seam thickness was constructed for each grade of coal. The distribution for bituminous coal is shown in figure 50 as a plot of cumulative coal-in-place v. minimum total seam thickness.
2. By examining data on production rates per foot of seam thickness for existing wells, values of 3 MCF/D/ft (bituminous), 1.2 MCF/D/ft (subbituminous), and 0.6 MCF/D/ft (lignite) were estimated for the production rates per foot from the coal resource in place. Then, for each grade of coal, minimum total seam thickness was converted to minimum "per well" production rate. This rate can, in turn, be converted into minimum gas price necessary to pay for the well.
3. It is assumed that gas recovery will be 50 percent of the total gas-in-place in coal seams satisfying the minimum thickness criteria, and that a random 10 percent of the coal-in-place will not be available for drilling.[18] Using these values and the assigned values of gas content (200 cubic feet per ton for bituminous, 80 CF/t for subbituminous, and 40 CF/t for lignite), cumulative coal-in-place can then be converted to recoverable gas resource.
4. The final result is a relationship between the recoverable resource and gas price. The estimated recoverable gas resources for three gas prices, assuming the gas to be used onsite without compression, are shown in table 59.

[18] Neither of these values are further substantiated in the report.

**Figure 50.—Estimated Distribution of Bituminous Coal by Seam Thickness**




SOURCE: National Petroleum Council.

The report does not give results for the case where the gas is scrubbed, compressed, and gathered for delivery to a pipeline. However, comparison of plots of gas price v. necessary production rates for onsite use and pipeline sales (figs. 4 and 5 in the NPC report) imply that pipeline delivery will add approximately $1.00/MCF to production costs. The actual effect on producer incentives is not clear, however. On the one hand, it is not uncommon for pipelines to pay for gathering and compression costs, which reduces the gas price required by producers to make a profit. On the other hand, for existing coal bed methane projects, initial compression and gathering cost generally have fallen on the producers.[19]

### Kuuskraa and Meyer[20]

A large portion of Kuuskraa and Meyer's gas-in-place estimate of 550 TCF was recognized as being within coal seams that were too thin or whose gas content per unit volume was too low to exploit. Assuming the favorable resource to occur only in bituminous coal seams greater than 3.5 ft thick and sub-bituminous seams greater than 10 ft thick, Kuuskraa and Meyer estimated that about 135 TCF of methane is present in the most favorable coal seams. The technically recoverable resource was determined to be 30 to 45 percent of the favorable resource, or 40 to 60 TCF, based on calculations of the amount of gas

[19] Vello Kuuskraa, Lewin & Associates, Inc., personal communication, 1984.

[20] V. A. Kuuskraa and R. F. Meyer, "Review of World Resources of Unconventional Gas," IIASA Conference on Conventional and Unconventional World Natural Gas Resources, Luxenburg, Austria, June 30-July 4, 1980.

that would desorb from the coal.[21] The KM estimate does not specify price constraints, but the thickness limits used to define the favorable resource do appear to imply a price range. Using basically the same methodology, a predecessor Lewin & Associates report[22] projected that 11 ft thick subbituminous seams in Colorado could be economically developed for gas production at $3.00 to $4.50/MCF in 1977 dollars, or about $5.00 to $7.00/MCF in 1983 dollars. Consequently, it seems likely that most of the 40 to 60 TCF of technically recoverable gas could be economically recovered at gas prices of $5.00 to $7.00/MCF (1983$).[23]

### Gas Research Institute[24]

GRI estimated recoverable gas resources by polling experts to determine how much gas they thought was present at various price levels, using existing or advanced technologies. The results of this poll are given in table 59.

## Estimate Comparison and Uncertainties

In general, the estimates of recoverable resources are quite similar, with the exception of the pessimistic NPC estimate for moderate priced gas (2.5 to 5.0 TCF at $2.50/MCF in 1979$ or $3.35 in 1983$). For high-priced gas, in the range of $5.00 to $10.00/MCF (1983$), a range of 20 to 60 TCF of recoverable gas would appear to agree well with all three studies.

In OTA's opinion, however, this apparent agreement should be viewed with caution. Of the three unconventional resources examined in this report, coal seam methane has the least production experience and the poorest data base to guide recoverable resource estimates. As a result, the two studies that used an analytical approach to estimating the recoverable resources—NPC and Kuuskraa and Meyer—use very broad assumptions and may be subject to considerable error,

The NPC report has made several assumptions that appear vulnerable to error. For example, the assumption of a 50 percent average recovery of the gas-in-place appears to be unrealistically high. Seams in the Black Warrior Basin in Alabama currently being developed by U.S. Steel do appear to have a potential recovery of about 50 percent,[25] but this area is one of the **best** methane prospects at present. A second assumption, that historic values of production rates per foot of seam thickness can be used to project future production rates, is probably too pessimistic. The NPC report notes that they had been told that future close-pattern drilling will be more productive than existing wells, which for the most part are isolated and do not represent efficient gas recovery. Recent performance data and research results appear to verify this production behavior (see discussion on *Production Methods,* above). Another problem with the use of the historic data is that the values of production per foot of seam thickness vary widely and randomly both between and within separate coal beds. In the limited sample obtained by the NPC, production varied between O and 12.3 MCF/D/ft.[26] This wide variation implies that the use of an average can introduce substantial error into the calculation.

The NPC also has assumed that a well's gas production will experience an exponential decline from its initial flow rate. In reality, flow rates often have been observed to **increase over a period of time as water drawdown increases the reservoir** rock's relative permeability to gas and decreased pressure increases resorption from the coal surfaces. Figure 51 shows plots of production rates over time to illustrate this phenomenon.

The NPC calculations of minimum coal seam thicknesses for economic gas recovery at various prices appear to be conservative in comparison to their own data. For gas prices in the $2.50 to $5.00 (1 979$) range for onsite use (and, presumably, about, $3.50 to $6.00 for pipeline sale),[27] the estimated minimum coal seam thicknesses for

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[21] Ibid.

[22] Lewin & Associates, Inc., *Enhanced Recovery of Unconventional Gas,* op. cit.

[23] Confirmed by Vello Kuuskraa, Lewin & Associates, Inc., personal communication, 1984.

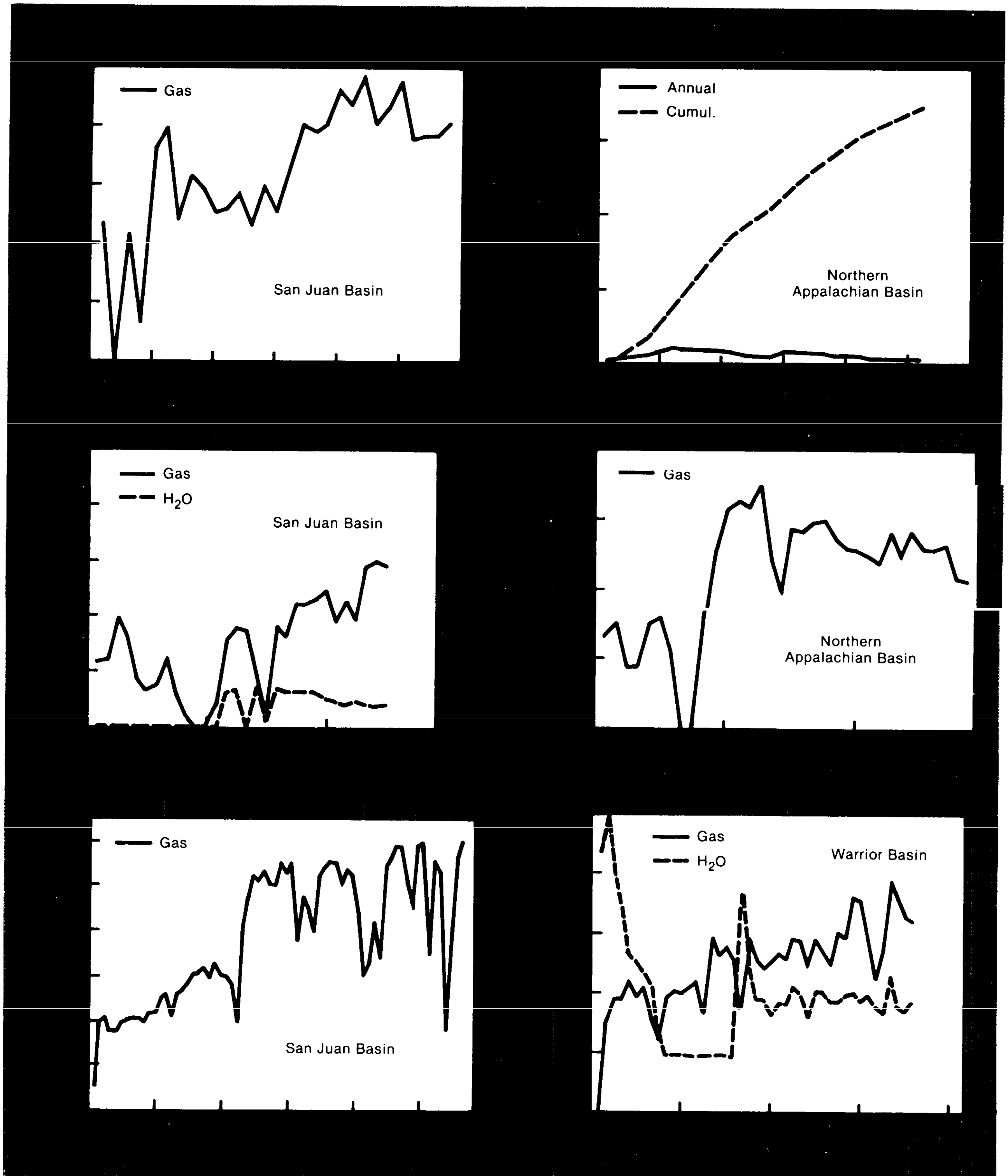
[24] Gas Research Institute, *Position Paper; Unconventional Natural Gas,* May 1981.

[25] Vello Kuuskraa, Lewin & Associates, Inc., personal communication, 1984.

[26] National Petroleum Council, *Unconventional Gas Sources: Coal Seams,* June 1980, table 7.

[27] Because pipeline sale may require the producer to incur costs for compression, liquids removal, contaminants removal, etc.

**Figure 51.—Well Production Histories in San Juan and Other Basins**




SOURCE: National Petroleum Council, *Unconventional Gas Sources: Coal Seams,* 1980.

bituminous coals range from 45 to 20 ft, corresponding to production levels of 135 to 60 MCF/D. The NPC data on actual wells, however, indicate that seam thicknesses in all cases examined were less than 25 ft and most were less than 10 ft, with production rates in all cases less than 70 MCF/D. Although the sales price of the produced gas and the profitability of the wells is not known, presumably some of these wells are profitable, and it does not seem likely that the prices paid for this gas could be much above the given range. This implies that the cost of these wells must have been lower than the NPC's calculated average well costs.

On balance, the examination of uncertain assumptions in the NPC study appears to indicate that their analysis may have been overly pessimistic.

The Kuuskraa and Meyer analysis differs substantially from the NPC analysis, especially because it **calculates recovery efficiency from an analysis of diffusion from the fracture network rather than assuming a recovery efficiency. This exposes the** KM analysis to some different kinds of uncertainties than those encountered by NPC. In particular, as noted in the earlier Lewin report,[28] the results are extremely sensitive to assumptions about the fracture intensity in the seams and the diffusion constant. For example, for Western coals, a change in the spacing between vertical fractures, from 1- to 5-ft intervals, reduces the 10-year recovery efficiency from 30 to 2 percent, essentially eliminating the economic recovery potential from these coals. Fracture intensity is not well-documented, especially for deeper coals.

Another potential problem with the KM analysis is that it is uncertain whether or not its simple diffusion model adequately represents the actual physical production mechanism in the coal seam. For example, the model and associated assumptions imply uniform production behavior across the seam, whereas in reality production behavior in existing coal seam methane projects (i.e., the Black Warrior development) has fluctuated widely from well to well.[29] This implies that we do not yet fully understand the gas production mechanism.

Because of the substantial remaining uncertainties and the lack of recent economic analyses that could take into account the latest understanding of the nature of the coal seam methane resource, OTA is reluctant to project a new estimate of the recoverable resource, However, in our opinion the NPC estimates for moderate prices–e.g., 2.5 TCF (at 15 percent rate of return) for gas prices of $2.50/MCF in 1979$ ($3.35/MCF in 1983$)—are overly pessimistic, and are based on past experience that does not reflect recent production capabilities associated with improved operating practices such as closer well spacing. What is critically needed is a reevaluation of the economics of recovering this resource given our better understanding of the resource and improved production methods. Information that would help such an estimate is a disaggregation of the resource base based on gas content as well as seam thickness. The data collected for the DOE basin analysis may be sufficient to provide the basis for a new analysis along these lines.

## Annual Production Estimates

Both NPC and GRI calculated annual production estimates. NPC estimated annual production through the year 2000 for both production from vertical wells and from shafts with horizontal holes. The vertical well development scenario extends over a drilling period of 18 years with recovery of the resource for 28 years. The development schedule requires beginning with 80 rigs the first year and adding 80 rigs in each of the next 7 years, with each rig drilling 45 producing wells per year. The resulting annual production estimates are included in figure 52.

For production from shafts with horizontal holes, the NPC assumed that 50 shafts would be drilled in the first year, with a 20-percent increase in the rate of adding new shafts every year, At this drilling rate, a 22-year program would be required to recover the total projected gas resource

[28] Lewin & Associates, Inc., *Enhanced Recovery of Unconventional Gas*, op. cit.

[29] Vello Kuuskraa, Lewin & Associates, Inc., personal communication, 1984.

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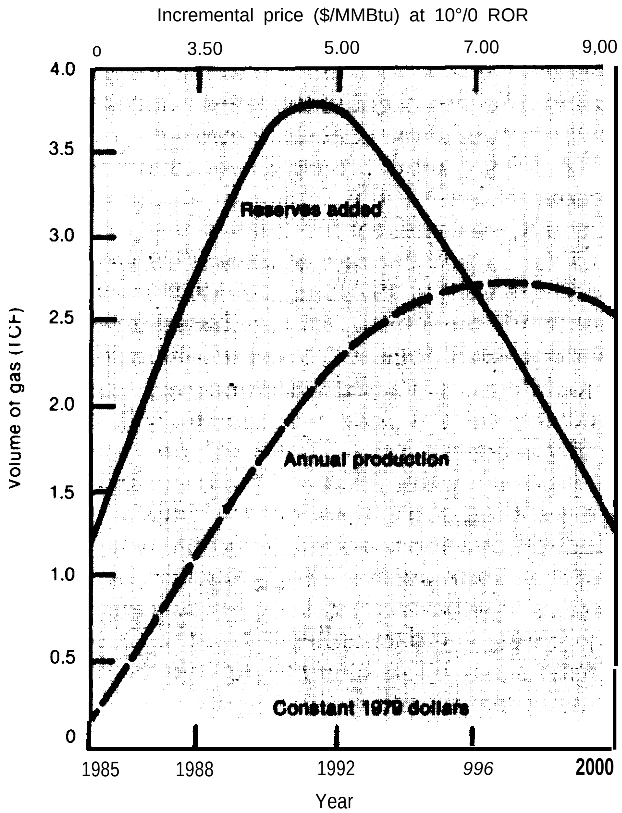
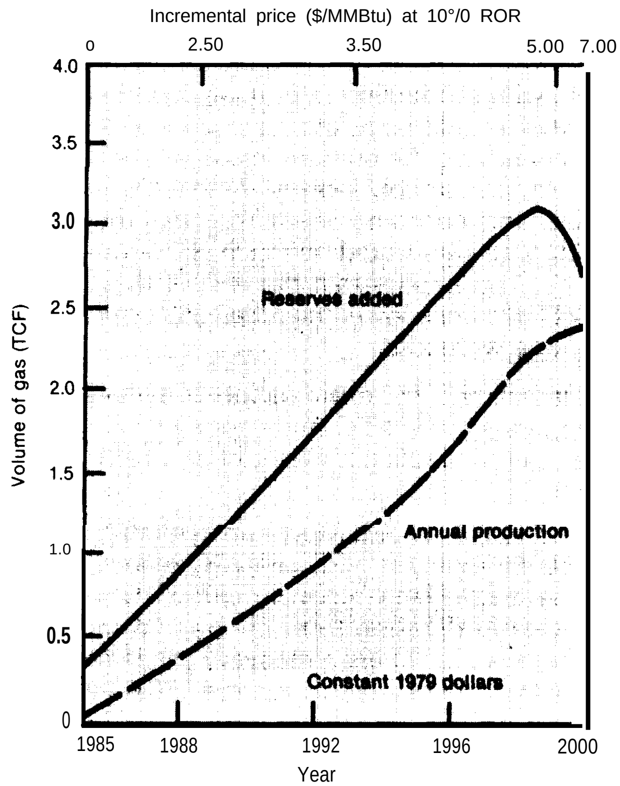
**Figure 52. —Annual U.S. Production Rates of Coalbed Methane as a Function of Time— Vertical Wells**




SOURCE National Petroleum Council

**Figure 53.- Annual U.S. Production Rates of Coalbed Methane as a Function of Time— Horizontal Wells**




SOURCE: NPC.

in **a** period of 35 years. The annual **production** rates are depicted in figure **53.**

**GRI used the recoverable resource estimates acquired from the poll and further assumed production and drilling rates. Production rates were estimated at 30 and 100 MCF/D** for existing and advanced wells, respectively. The number of wells drilled per year was assumed to be 200 from 1983 to 1986 with a 10 to 15 percent increase per year thereafter. Utilizing the resource base as a limit, annual production estimates were calculated. The 1990 and 2000 production estimates are included in table 60.

The NPC study assumes that the gas price will increase steadily to $9/MCF (1 979$), Given current and expected future market conditions, this assumption appears unrealistic. On the other hand, if, as it appears, a majority of the recoverable resource can be recovered at prices on the order of $5/MCF (1979$), and if little is required in the way of technologic advances, increasing levels of production might still be expected. What is required is an increased level of producer interest-interest which at present is constrained by questions of ownership, mine safety, environmental concerns, and other institutional considerations. Some of these issues are discussed below.

## Legal Constraints

Court decisions to date have attempted to resolve several legal questions associated with coal seam methane production, but without much success. Previous litigation has centered on the issue of resource ownership and whether the methane is a resource in its own right or an intrinsic part of the coal. The *U.S. Steel v. Hoge*

**Table 60.–GRI Coalbed Methane Annual Production Estimates (TCF)**

| Market price (1979$/MCF) | 1990 Existing technology | 1990 Advanced technology | 2000 Existing technology | 2000 Advanced technology |
|---|---|---|---|---|
| $3.00 | 0.06 | 0.22 | 0.29 | 0.95 |
| $4.50 | 0.07 | 0,23 | 0.35 | 1.2 |
| $6.00 | 0.07 | 0.24 | 0.42 | 1.4 |

SOURCE GRI

**case** of March 1980 set a precedent on both these issues. Although lower court decisions determined that methane is a natural gas occurring in coal, and that the land owner owns the methane until the gas rights are released, in December 1983 the Pennsylvania Supreme Court reversed that decision, remanding ownership to the coal owner.

The recovery of coalbed methane on Federal coal lands also is burdened with unanswered legal questions. The current position of the Solicitor's Office of the Department of Interior is that ownership of a coal lease does not include rights to the coal bed gas, but that a reservation of gas does,[30] and that coalbed gas is leasable under the oil and gas leasing provisions of the Mineral Leasing Act. This position has not been tested in the courts, however. Drilling permits for coal seam methane recovery have been issued, although administrative delays are a problem.

## Environmental Constraints

The primary environmental issue associated with coal seam methane production is disposal of the water produced with the gas in those coal seams characterized by high water contents. Since dewatering is a primary production requirement, large volumes of water must be pumped from the subsurface. The quality of the water varies from slightly acidic to slightly alkaline depending on the site location. The environmental regulations of the State determine whether the water must be treated, and such decisions will influence the economic viability of the recovery project.

[30] A detailed summary of the legal situation is presented in J. H. Kemp, "Coalbed Gas: Recent Developments in the Ownership and Right to Extract Coalbed Gas," *The Landman,* November 1982.

## Institutional Barriers

There are other factors that will influence the contribution of coal bed methane to future supply. Institutional barriers characteristic of the coal industry will deter or possibly preclude production in some instances. A primary institutional barrier is the lack of interest exhibited by the coal companies. According to industry analysts, since the companies' primary interest is coal mining, they tend not to want to become involved in the more long-term nature of the methane production industry, particularly when the economics are marginal. Investment incentives may be required to create interest in producing the methane rather than venting. Alternatively, if new analyses demonstrate a real economic advantage to producing gas prior to mining, the coal industry may become more interested in overcoming problems created by the mining schedule. One problem with degassing prior to mining is the short time period between the beginning of gas production and the mine opening that has often been allowed. Numerous wells are required, incurring high capital costs which cannot be recouped without a longer production period.

Another institutional barrier to production is the strong concern with worker safety associated with coal mining. The issue of whether stimulation causes unacceptable damage to the mine ceiling has not been resolved. The Bureau of Mines initiated a program at four sites to determine the effects of stimulation. Due to various problems, however, work was completed at only one site. The site evaluation indicated that there were no adverse effects on the mining operation, but the limited extent of the test precludes extrapolation of the results to other sites. No firm evidence exists to link stimulation effects to mine collapse at numerous other operating facilities, but until the technique is proven not to cause damage, many companies will be reluctant to invest.

In OTA's opinion, the above uncertainties, coupled with the technical and economic uncertainties mentioned in the discussion of recoverable resources, imply that the current production projections are not adequate, and effort should be focused on establishing a new, more scientifically based estimate of the potential contribution of coal seam methane to future U.S. gas Supply.

# Appendixes

# Appendix A
# Calculation of Additional Reserves From Increased Gas Recovery in Old Gasfields

OTA calculated the effects of higher gas prices on gas recovery in "old" gasfields by modifying a previous analysis of those effects conducted by the Shell Oil Co.[1] The OTA analysis is discussed in detail in a recent OTA staff memorandum and is summarized here.

The analysis focuses on the expansion of "old gas" reserves, which are defined here as all reserves that do not qualify for "new natural gas" status under the Natural Gas Policy Act (NGPA). In general, old gas is gas in reservoirs that were discovered (and reserves reported) prior to about mid-1977; however, the precise boundaries are more complicated than this.

## Shell's Analysis

The Shell study assumed that all old gas would remain at low prices under the NGPA and would rise to $3.50/MMBtu, the assumed free market price, under a price decontrol policy. Shell calculated the effect of a $3.50 gas price on recovery in the Nation's old gasfields by the following method:

1. **Calculate the Nation's "responsive reserves," that** is, the old gas reserves that might grow if their prices go up. Some reserves, such as Alaskan North Slope gas, gas dissolved in oil, and, to a lesser extent, gas in water-drive reservoirs will not respond much to a gas price increase and were not included in the analysis of reserve growth. For example, gas dissolved in oil is responsive primarily to **oil** prices, because the value of the oil in the reservoir far outweighs the value of the gas. If oil prices go up, more oil will be produced and thus more gas will be co-produced with it.

Shell's estimate of responsive reserves in 1981: 115 TCF.

2. **Calculate reserve growth in sample fields** where adequate data are available. Shell evaluated the effects of a price increase to $3.50 on lower abandonment pressures and well reworkings, infill drilling, and well stimulation for 14 large sample fields. The lower abandonment pressure calculation involves computing the gas flow that will produce revenues equal to operating costs[3] for the new and old gas prices. The difference in reservoir pressures corresponding to the "new" and "old" flows, and the additional reserves corresponding to this pressure difference can then be calculated by using the physical gas laws. The infill drilling calculations were made using reservoir simulation and extrapolation from previous infilling experience. The well stimulation calculations are based on an engineering judgment that an additional 1.5 percent can be added to ultimate recovery by this means:

Reserves remaining in sample fields . . . . 41.3 TCF
Reserve growth, lower abandonment pressures and well reworking . 9.6 TCF
Reserve growth, infill drilling ... ., . . . . . . 7.6 TCF
Reserve growth, well stimulations = 1.5 percent of ultimate recovery[4]

3. **Scale up the sample results to the Nation,** assuming that, except for well stimulations, the results will scale by the ratio of the remaining reserves:

Scaling factor = 11 5/41.3 = 2.8
National reserve growth for lower abandonment pressures and well reworkings = 9.6 X 2.8 = 27 TCF
National reserve growth for infill drilling = *7.6 X 2.8 = 21* TCF

By examining available production records and estimates of remaining reserves, Shell estimated that the ultimate recovery represented by the 115 TCF of responsive reserves is **475** TCF, thus:

National reserve growth for well stimulation =
0.015 x 475 = 7 TCF

Assuming that 3 TCF of the infill drilling would occur anyway at presently available prices (an incentive price of $2.75/MMBtu in mid-1983),

Total national reserve growth due to higher prices =
27 + 21 + 7 – 3 = 52 TCF

## OTA's Modifications to Shell's Analysis

OTA has made a number of modifications to Shell's original calculations based on a detailed review of Shell's methodology, an evaluation of alternative data sources, a review of literature on infill drilling and other topics related to gas recovery, and a number of telephone interviews with geologists and petroleum engineers. The most important of the modifications are:

1. **Scaling to the Nation. OTA** determined that an appropriate scaling factor should be related as closely as possible to the original volume of gas in the fields. The basis of Shell's scaling factor, remaining reserves, is tied closely to the production history of the fields.

[1] C S Matthews, *Increase in United States "old" Gas Reserves Due to Deregulation,* Shell Oil Co , April 1983

'Office of Technology Assessment, *Staff' Memorandum on the Effects of Decontrol on Old Gas Recovery,* February 1984

[3] This is approximately the abandonment point for the well, since profits are zero at this point

[4] Ultimate recovery = cumulative production plus remaining reserves

Ultimate recovery, on the other hand, is more directly related to the original gas volume and is a more appropriate basis for the scaling factor. Using Shell's own calculations, the use of ultimate recovery as the basis for the scaling factor yields an increase in the expected national reserve growth of 36 percent (all else being equal).

2. **Responsive reserves. As noted above, Shell assumed that all old gas would remain at low prices under the NGPA, so that, for the calculation of responsive reserves,** Shell estimated the **total** old gas reserves and subtracted only those reserves that would be physically unresponsive to higher prices. However, the NGPA provides for the decontrol or price escalation of most old intrastate reserves by 1985, and the decontrol by 1985 or 1987 (depending on depth) of all gas from infill wells in old intrastate fields. Consequently, these reserves will receive a high decontrolled price whether or not any additional decontrol measure is passed, and thus are not "responsive" to such a measure . . . . they should be subtracted from Shell's calculated responsive reserves. Shell also made some minor errors in its original calculation of total old gas reserves; it treated all "extensions" added to reserves since 1977 as old gas, whereas some of these reserves qualify as "new" NGPA Section 102 gas and should have been excluded from the calculated total of old gas reserves.

Data on the amount of reserves in each NGPA category are not available. OTA used data on reserve volumes in interstate and intrastate commerce, interstate pipeline purchases by NGPA category, and limited production data by NGPA category to estimate the volume of old gas reserves in each category, and the volume of responsive reserves. Our estimate of responsive reserves was 63.4 to 71.4 TCF for lower abandonment pressures and well stimulations, and 59 to 66 TCF for infill drilling, as compared to Shell's 115 TCF estimate for each category. Consequently, all else being equal, Shell's results are overstated by the ratio of "incorrect" to "correct" reserves, or by a factor of about 1.6 to 2.0.

3. **Abandonment pressures. Shell's estimates of the current abandonment pressures** in its sample fields generally are considerably higher than the estimates of alternative analysts, for example, the American Gas Association's Committee on Natural Gas Reserves. A higher current abandonment pressure implies a larger growth potential, so applying the alternative, lower pressures would yield a lower estimate of the additional reserves available from the growth of older fields. Specifically, applying the alternative pressure estimates in those fields where such estimates are available more than halves the estimates of growth potential, from 8.1 TCF to 3.0 TCF. The uncertainty associated with these alternative abandonment pressure estimates was factored into OTA's estimates of field growth potential.

**4. Infill drilling.** A key point of contention with Shell's analysis of infill drilling is the extent to which the potential reserves may be available at today's prices without any legislative changes. Shell's prediction that only 3 TCF of a 21 TCF potential would be forthcoming at today's prices is based partly on its assumption that the low level of infill drilling activity of the past few years must reflect a lack of economic prospects. However, a variety of factors other than an inadequate price may have played a role in the current inactivity. These factors include the current gas surplus, opposition by pipelines or consumers, s opposition by other producers in the same field,[6] and State prorationing rules that prevent producers from increasing production rates. OTA's discussions with producers have lead us to believe that more than 3 TCF of the total infill potential would eventually be drilled at current prices. The range of infill potential in Scenario 1 reflects the possibility that as much as one-third of Shell's "after decontrol" infill potential could occur eventually without any further legislative change.

[5] Bec a use the current infill Incentive price of about $2 .85/MMBtu applies to all gas from the infill well, Including gas that could have been produced from adjacent wells at a lower price.

[6] Because the potential for drainage across the field means that the other producers would have to infill also or face the loss of some of their gas.

# Appendix B
# Fracturing Technologies

## Introduction

A characteristic of "unconventional resources" is that, while increased prices generally are an important condition for full commercialization, new technology developments are also required. In the long run, technology may have more impact than price on the amount of gas recovered. Studies of unconventional resources that OTA has reviewed have concluded that the amount of gas that could be produced with existing technology at prices considerably higher than today's is less than the amount of gas that could be produced with advanced technology at current prices for new gas. For example, the National Petroleum Council's tight gas study estimates that more gas can be produced for $3.00 per thousand cubic feet (MCF) with advanced technologies than can be produced for prices up to $9.00/MCF using base case technology. In response to this perception, a considerable amount of Government and industry research effort has gone into developing more advanced technologies for unconventional gas recovery,

In the past 5 years the state of technological development has advanced. With and sometimes without additional Government financing, producers have been willing to try innovative approaches. Nevertheless, a high failure rate still exists in probing certain types of unconventional gas formations. The following discussion describes successful new developments in fracturing technologies and delineates areas where work remains to be done. This appendix will serve to give the reader more insight into the validity of the assumptions used in the various estimates of recoverable resources and production potential.

## New Technology Developments in Fracturing

The objective of fracturing a low-permeability reservoir is to increase the surface area of the formation that is in direct contact with the well bore. The pressure gradient between the lower permeability formation and the higher permeability fractures is the driving mechanism for the gas flow. Thus, the greater the area over which such a gradient can be established, the larger the volume of gas flowing at a given point in time.

Technologies for fracturing gas reservoirs are not new. Explosives have been used in Devonian shales since the late 1800s. Detonation of explosives shatters the rock immediately around the well bore, effectively increasing the well bore diameter. A large-scale variation on this theme was tried in the late 1960s in tight sandstone formations using nuclear explosives. The generally unsatisfactory results (possibly due to melting of the reservoir rock from the heat of explosion or permeability damage due to compaction of fine particles) and the lack of public enthusiasm for potentially radioactive gas put a quick end to this program.

### Hydraulic Fracturing Technologies

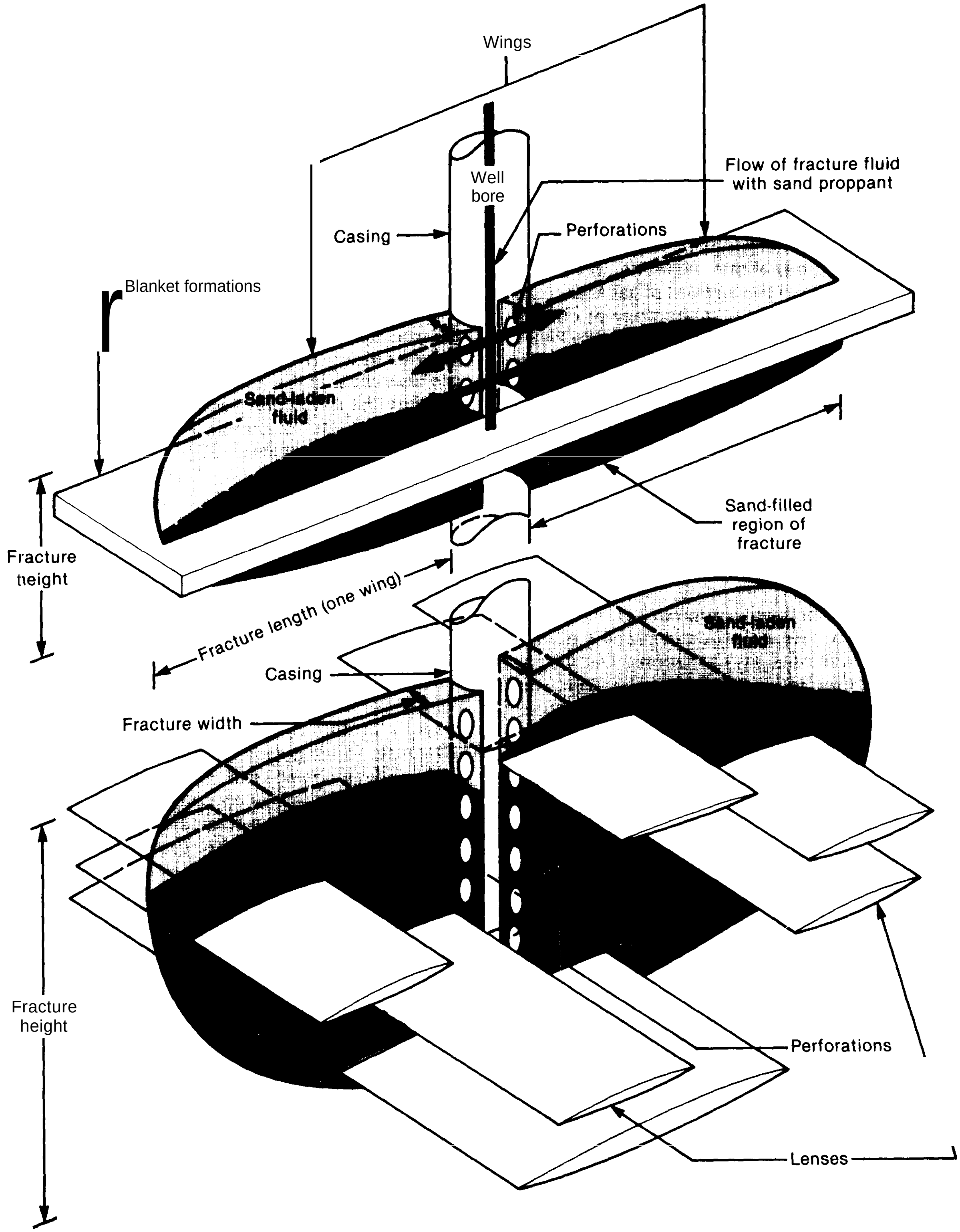
Hydraulic fracturing is the most commonly used fracturing technology today. The concept was first developed in the 1940s for use in conventional oil and gas reservoirs. In the early 1970s **producers began to increase the size of the fracture treatments to generate longer fractures, on the order of 1,000 ft in low-permeability sandstones.**[1] **This technique, known as massive hydraulic fracturing (MHF), is now a common means of well completion in the tight sand formations, although it is certainly not applicable** in all cases. Devonian shale and coal seam reservoirs use more conventional size hydraulic fracture treatments to create fractures ranging from 100 to 500 ft. Fractures in these types of reservoirs are designed to intersect natural fractures, which serve as the primary pathways for gas flow.

Hydraulic fractures are created by pumping large volumes of fluid down the well bore. The fluid exerts pressure on the rock formation, eventually creating a fracture. Fluids generally carry proppant materials, such as clean coarse sand, which are left in the fractures and hold them open when the fracturing fluid is removed. The induced fracture has a considerably higher permeability than the surrounding formation. Hydraulic fractures tend to be unidirectional, generally extending out as wings in opposite directions from the wellbore. By convention, their length is measured along one wing. Their direction and orientation (vertical, horizontal, or inclined) are controlled by the regional tectonic forces and the depth of the target formation. Most fractures at depths greater than 2,000 ft are oriented in the vertical plane. Figure B-1 schematically represents a hydraulic fracture.

Major research efforts in fracturing technology have focused both on increasing the fracture length and

[1] C.R. Fast, G. B. Holman, and R. j. Corlin, "The Application of Massive Hydraulic Fracturing to the Tight Muddy J Formatlon, Wattenberg Field, Colorado, " *Journal of Petroleum Technology,* January 1977, pp. 10-16

**Figure B-1.—Conceptual Fractures Created by Massive Hydraulic Fracturing in Blanket and Lenticular Formations**



solving some of the problems that reduce the effectiveness of the fracture in increasing rates of gas flow.

Maximizing the effective length of a fracture is not simply a function of increasing the volumes of fluid pumped into the well bore. One must make sure that the proppant is transported to the end of the fracture, and effectively holds the fracture open once the fracturing fluid is removed. Other problems that must be overcome include minimizing damage to the formation caused by the fracture fluids and containing the fracture within the "pay interval," the layer where gas is present. If the fracture intersects a permeable zone that allows the fracturing fluid to "leak off" at a high rate, further penetration of the fracture may become impossible because the fluid loss prevents further pressure from being built up.

Each of the objectives of fracture research will be discussed in turn:

**Maximizing High Conductivity Fracture Length.–Accomplishing this objective involves choosing appropriate fracture fluids and proppants.** The proppants should be strong enough not to crush as the fracture closes, and of sufficient diameter to overcome any tendency to become embedded in the formation. Also, they must be light enough to be carried by the fracturing fluid to the design fracture length without settling.

Conventional practice is to use clean rounded sand as the proppant material. It is the least expensive proppant and, at shallow and intermediate depths, has sufficient strength to hold the fracture open without crushing. At greater depths where closure pressures are higher and proppant crushing prevalent, a stronger material is needed.[2] Producers most commonly use sintered bauxite under these conditions. However, bauxite has two drawbacks–high cost and high density. Because of the latter, it is difficult to transport the bauxite particles to the end of the fracture. Service companies are rapidly developing alternate intermediate and high strength proppant materials. A number of these materials, including ceramic beads and resin-coated sands, have lower densities than bauxite and appear to have sufficient strength for most fracture applications. More work needs to be done to develop materials with densities lower than sand and adequate strength to maintain high fracture conductivities.

The need for a fracture fluid with a high capacity to carry proppants in suspension has led to the development of very sophisticated fluids. These include water- and hydrocarbon-based polymer liquids and gas-charged emulsions and foams.

[2] R. A. Cutler, D. O Enniss, A. H Jones, and H. B. Carroll, "Compa risen of the Fracture Conductivity of Commercially Available and Experimental Proppants at Intermediate and High Closure Stresses, " *SPE/DOE Symposium on Low Permeability Gas Reservoirs,* SPE/DOE 11634, 1983.

The water-based fluids use organic polymers for friction reduction, fluid loss control, and viscosity enhancement. The polymers are long chains of organic molecules which bond loosely with the water, forming gels. The resultant fluid is thicker than water and has a higher surface tension. It flows with less turbulence, can suspend greater volumes of proppants and does not leak off into the formation as rapidly as pure water.

Probably the most significant technical development in fracturing fluids is the process of **cross-linking.** Cross-linking is a chemical reaction which bonds polymer chains together, effectively increasing the viscosity of the fluids as much as an order of magnitude. The reaction is timed so that cross-linking occurs just as the fluid arrives at the fracture entrance. The increased pressures required to pump the thicker fluid will widen the fracture and the enhanced viscosity can carry the proppant greater distances. At the end of the treatment the fracture fluid warms up to the higher reservoir temperatures and the cross-linked polymers break down. Now significantly lower in viscosity, the fluid can leak off into the formation or flow back out of the wellbore, leaving the proppant in place.

Hydrocarbon-based fracture fluids behave similarly to water-based fluids and can also be cross-linked. They are used in instances where water-based fluids are likely to cause significant formation damage—as in the presence of water-sensitive clays. However, in gas-bearing reservoirs the introduction of a third phase (oil, in addition to gas and water) may further impede the flow of gas in the formation.

**Minimizing Formation Damage.—In addition to fluids designed to improve proppant transport,** more exotic fracture fluids have been designed to address the problem of formation damage. Fracture fluids have been a major factor in causing formation damage. Fluid leak-off into the formation can block pores, especially if the gels are not completely broken down. introduced fluids can also cause clays to swell, or dislodge fine particles to block pores.

All three types of unconventional gas reservoirs are susceptible to formation damage. Devonian shales may be the most affected because they have naturally low water content and high clay content. Devonian shales have, as a consequence, served as a testing ground for a number of the new fracturing fluids.

Many of the fluids developed to minimize formation damage use a gas phase to reduce the amount of water required. Foamed fluids are gas-in-water emulsions, where the surface tension of the bubbles holds the proppant in suspension. Such fluids cannot transport large volumes of proppant long distance—they are generally used for shorter fractures. Nitrogen (N,) is the most common gas used in foamed fluids, although $CO_2$ can also be used. Producers are experimenting with increasing the percentage of gas from 75 to 90 percent of the total fluid volume.

Pure $N_2$ has also been used as a fracturing fluid. It is not an efficient fracturing fluid as it requires very high injection pressures. However, nitrogen fracturing has proved very effective in increasing gas flow because it does not adversely affect the formation. Nitrogen gas cannot carry proppants, therefore it is only effective at shallow depths where the fractures are less likely to close. Whether wells fractured with nitrogen will maintain higher production levels over the long term is still unknown.

Some wells have been fractured using liquid $C0_2$, which has the ability to transport proppants. As the liquid $C0_2$ warms, it reverts to the gas phase and easily flows back out of the hole with minimal damage to the formation. Liquid $CO_2$ fracturing is a relatively expensive process and somewhat more dangerous to use than foamed fluids, In addition, the casing and pumping materials must be capable of withstanding very low temperatures.

The tradeoffs of minimizing formation damage, transporting proppants, and containing costs all enter into the decision of which fracture fluid is used. Generally, an important element in the decision should be laboratory compatibility tests between formation cores and the proposed fracturing fluids, which can identify potential damage problems.

**Containing the Fracture within the Pay Interval.–As a fracture propagates outward from the wellbore it may also grow vertically up or down, Vertical growth occurs at the expense of lateral growth, thus reduces the effective length of the fracture** for the same volume of fluid pumped. Those portions of the fracture which extend above and below the gas-producing interval are essentially wasted; also, they may extend into water-bearing strata which will adversely affect gas flow.

**It** has been recognized in the last few years that the main factor controlling containment of a fracture is the difference in the stress characteristics of the rocks making up the producing and nonproducing zones. The stress on the rocks, or "in-situ stress," is a function of the mechanical properties of the rock and the regional stresses acting on the rock. Thus, the same type of rock at different locations or depths or in different tectonic environments may have different in-situ stress characteristics. A sand-shale interface in the Cotton Valley Sands may effectively contain a fracture within the sand zone. A fracture in the Piceance Basin may break through a similar sand-shale interface. Similarly, different rocks will have large differences in their mechanical resistance to fracturing and thus require substantially different applied pressures for fracturing.

No commercially available technologies exist today that successfully deal with fracture containment. Some recent research efforts have focused on developing innovative techniques to control the growth of fractures out of the pay zone. GRI is testing three approaches:[3]

- **Fracture initiation placement–the well casing is perforated above or below the pay zone allowing the fracture to grow vertically into the producing interval. A field test of this technique was performed in July 1983.4 Preliminary results** indicate increased flow but further cleanup is necessary before final results can be assessed.
- **Controlled process zone–the fluid viscosities and pumping rates are controlled to get preferential initial leak-off in the pay zone. This should result in** more penetrating rather than taller fractures. This technique is still being tested in the laboratory.
- **Lightweight additives–impermeable floating** proppants are used to seal off upper, non-producing portions of the fracture. Appropriate proppant materials are currently being tested.

**Predicting and Monitoring Fracture Behavior.–** Another important research objective in improving fracturing technology is to develop techniques to predict and monitor fractures. To know in advance how a fracture is likely to perform or to be able to tell in the field whether a fracture is conforming to design parameters increases the chances that stimulation will be successful. Furthermore, as fields become more developed, it is important to know the direction and length of a fracture, and thus the drainage area of a well in order to minimize interference from subsequent wells. Fracture diagnostics probably is one area where the most innovation has occurred in the last few years.

*Predicting fracture* behavior.–State-of-the-art prediction of fracture behavior comes mostly from formulation of sophisticated mathematical models and comparison of the model results with results of laboratory experiments. There has been little field verification because of the cost and technical difficulty involved in obtaining a detailed picture of the physical results of fracturing.

[3] "GRI's Unconventional Natural Gas Subprogram, " Status Report, December 1982.
[4] "New Fracturing Technique Undergoing Tests, " *Oil and Gas Journal,* Aug. 8, 1983.

Current practice in the field is to use relatively simple analytical models against which to compare fracture behavior, proppant placement, fracture length, and well performance. Two commonly used models are the Perkins and Kern model and the Gertsma and De Klerk model. The first is considered by some practitioners to be the more reliable model for fractures extending laterally without significant increase in height, with the second more reliable for short fractures with length to height ratios less than one.[5,6]

More sophisticated models are being developed to deal with more complex situations such as fracture propagation response to changing stress fields, or intersection of an induced fracture with a natural fracture. Such models have been used occasionally to design actual field stimulations where preliminary investigation indicates a simplified model would give inadequate or misleading results. Use of complex models for field design is limited at present due to high costs, time required to run the simulations, and probably most importantly, inadequate input data. At present these models are mostly used as controls for design of experiments and for comparison with experimental results. The extent to which experimental results reproduce the simulated results both confirms the validity of the simulation and identifies the controlling parameters.

Laboratory experiments are conducted to observe fracturing behavior under controlled conditions. In these experiments, scale models are used to simulate field conditions. For example, a block of reservoir material can be placed in an experimental apparatus which can reproduce confining pressures and temperature conditions of the actual reservoir. Fluid is pumped into a hole drilled into the block, inducing a fracture. Sensors monitor strain buildup and release. Finally the fractured block can be sectioned to observe the fracture configuration. Experimental conditions allow certain variables to be held constant while others are varied to determine the effect each has on the fracture, One set of experiments was run to observe induced fracture behavior in the presence of an existing fracture system.[7] Results indicated that an induced fracture would cross an existing fracture only at high angles of approach (i e., close to perpendicular) or if the stress field created a strongly preferred fracture orientation. Otherwise the preexisting fractures would open, diverting fracture fluid and stopping the induced fracture from propagating.

The major problem with laboratory experiments is determining whether the laboratory conditions are truly representative of the reservoir environment. it rarely is clear whether the small-scale laboratory fracture would behave in the same fashion if it were increased to field scale. Consequently, the next step in predicting fracture behavior is the field test. Field tests are extremely expensive, and therefore few have been conducted. Perhaps the most useful are "mineback" experiments which excavate and expose an induced fracture, allowing comparison of actual behavior with predicted behavior and physical measurement of the rock, fracture, and fracturing materials.

Successful field-scale experiments of massive hydraulic fractures have been conducted at the Nevada Test Site in volcanic rocks.[8] These rocks are not particularly characteristic of tight sandstone reservoirs but the experiments still provided useful and frequently applicable information. One significant result indicates that fracture tortuosity (irregularities of the fracture path) significantly increases the pressure gradient in the fracture, leading to wider than predicted fractures.[9] Other studies demonstrated the mechanics of fluid leak-off and sand distribution.

Because of their expense, mineback experiments are no longer being conducted by the Department of Energy (DOE) or GRI.[10] Instead, field testing for understanding fracture behavior is focusing on experimental well tests. These tests rely on sophisticated in-well measurements to **infer fracture behavior** in contrast to the direct observations possible with minebacks.

The largest scale well test at present is the DOE Multiwell Experiment (MWX). This test consists of three wells drilled in close proximity to each other in a tight sands field in the Piceance Basin in Colorado. The multiple wells serve many functions. They allow collection and correlation of geologic data and provide testing sites for new logging tools. Perhaps most importantly, they provide sites to monitor behavior of fractures induced in one of the wells. A fracture has been completed in the blanket sand reservoir in this field and results have indicated the importance of an existing natural fracture system on fracture behavior and well performance. Subsequent stimulation treatments are planned to address specific problems of fracturing in lenticular formations.

[5]Johnston & Associates, Inc., "The Status and Future of Production Technologies for Gas Recovery From Devon Ian Shales, OTA contractor report No, 333-6810

[6]J. W. Crafton, "Fracturing Technologies for Gas Recovery From Tight Sands, " OTA contractor report, 1983

[7]T.L.Blanton, ' An Experimental Study of Interaction Between Hydraulically Induced and Pre-Existing Fractures " *SPE, DOE Unconventional Gas Recovery Symposium,* SPE/DOE 10847, 1982, pp 559-562.

[8]. R. Warpinski, L. D, Tyler, W. C. Vollendert, and D. A. Northrup, " Direct Observation of a Sand Propped Hydraulic Fracture, Sandia National Laboratory Report SAND81 -0225, May 1981.

[9], R Warpinski, "Measurement of Width and Pressure in a Propagating Hydraulic Fracture, " *SPE/DOE Symposium on Low Permeability Gas Reservoirs,* SPE/DOE 11648, 1983.

[10]Charles Komar, Morgantown Energy Research Center, personal communication, 1984.

Similar but smaller scale well tests are being conducted in Devonian shales to determine effectiveness of different types of stimulation in improving reservoir production.

*Monitoring fracture behavior.* –Most of the technologies under development to monitor fractures in the field are adaptations of existing geophysical and well logging techniques. They include magnetic, electrical, and seismic instrumentation as well as temperature, pressure, and radioactivity measurements (see box B-1). Some techniques such as temperature and radiation logs are only useful in the immediate vicinity of the borehole. They indicate fracture height under certain conditions but not depth of penetration.[11] Tiltmeters and microseismic measurements which record minute deflections and seismic disturbances caused by the propagating fracture may be able to measure fracture direction and total length, but cannot discern propped (effective) length. Superconducting magnetometers may have potential for determining propped length from magnetic material introduced with the proppant.[12]

Most of these technologies are still in the experimental stages. Their depth limitations, sensitivity, and overall accuracy have not yet been fully evaluated. Using a number of these technologies together would probably be the most effective way to collect data on a fracture[13] but for practical application would be too costly.

There are other constraints to widespread use of fracture diagnostic techniques. For example, adverse terrain and difficulty in obtaining surface access rights cause problems for methods which require widely spread surface arrays of detection equipment.[14,15] The extremely sensitive nature of the instruments and the necessity of measuring signals that are only marginally discernible above background noise requires very careful setup and monitoring that may not be achieved under ordinary operating conditions.

The technique most commonly used today to evaluate whether a fracture satisfies design criteria is pressure transient testing. This type of test generally is run after the fracture treatment is completed, although it can be useful as a pre-fracturing test as well. Essentially, a post-fracturing test matches the actual performance of a well for a given period of time against the simulated performance of a fracture of given propped configuration. This gives a **minimum estimate of the propped length.** The technique gives valuable empirical data on the flow rate and pressure decrease with respect to time for the well. However, it is generally considered as not providing sufficient information to allow producers to discern whether lower-than-predicted flows are due to fracturing out of the pay interval, inadequate fracture conductivity, or formation damage.[16]

Improved fracture diagnostic techniques may reduce some of the undefined variables (e.g., actual propped fracture length). This would allow the reasons for success or failure of a particular fracture treatment in a given formation to be better understood, resulting in improved fracture design.

## High Energy Gas Fracturing or Tailored Pulse Loading

This technique is dramatically different from hydraulic fracturing techniques, and is derived from earlier explosive fracturing. A propellant charge is used that can pressurize the wellbore at a slower rate than the conventional explosives, changing the characteristics of the fractures created.[17] The loading rate—i.e., the rate at which the energy stored in the gas is released—can be controlled to create different types of fractures. For example, at intermediate loading rates, fractures form radially around the well bore. At slow rates, fractures form in an analogous manner to hydraulic fractures, directionally controlled by the regional stress field. This technique may have significant potential for commercial use, especially because it causes little formation damage. Commercial application in the Devonian shales may occur in the near future. Application in tight formations is more problematic, however.[18]

[11] C. M. Hart, D. Engi, and H. E. Morris, "A Comprehensive Fracture Diagnostics Instrumentation Fielding Program," *SPE/DOE Symposium on Low Permeability Gas Reservoirs,* SPE 11810, 1983, pp. 461-485.

[12] M. D. Wood, C. W. Parkin, R. Yotam, M. E. Hanson, M. B. Smith, R. L. Abbot, D. Cox, and P. C)' Shea, "Fracture Proppant Mapping by Use of Surface Superconducting Magnetometers," *SPE/DOE Symposium on Low Permeability Gas Reservoirs,* SPE/DOE 11612, 1983,

[13] D. A, Northrup, A, R. Sattler, and J. K. Westhusing, "Multiwell Experiment: A Field Laboratory for Tight Gas Sands," *SPED(3E Symposium on Low Permeability* Gas *Reservoirs,* SPE/DOE 11646, 1983.

[14] Hart, Engi, and Morris, Op. cit.

[15] Johnston & Associates, Inc., OP. cit.

[16] This is a matte of some dispute, because some specialists claim to be able to distinguish among the possible causes of disappointing flows,

[17] Crafton, op. cit.

[18] S. A, Holditch, personal communication, 1984.

## Box B-1. --Well Logs

Well logs are measurements of rock formation characteristics taken by devices, called sondes, that are lowered into the wellbore on an electric wireline and transmit back information toa surface recording device. There are a great variety of these devices. The most common are:

1. Eletrical logs measure the electrical characteristics of the rock surrounding the wellbore before the well is cased. Electrical logs measure either resistivity or spontaneous potential.
   - Resistivity logs pass an electric current through the rock formation and measure its ability to conduct electricity. These logs help to determine the type of fluid contained in formations and the relative saturation of oil and water. There are a variety of resistivity logs, including:
     - –Induction logs, which measure formation resistivity in wells drilled with freshwater drilling fluids or with nonconductive fluids such as air or oil.
     - –Laterolog, which can identify thinner formations than ordinary resistivity logs. These are used with saltwater drilling fluids.
     - –Micrulog, which is used to identify the porous and permeable zones by measuring the resistivity of the thin layer around the wellbore that is invaded by drilling fluids.
   - The spontaneous potential log measures the electrical potential created by the differences in salinities between the formation water and drilling fluids. This log helps to differentiate between rock types (e.g., sand and shale) and to define formation water salinity.
2. Radioactive logs measure either the naturally occurring radioactivity in the rock formation or the response of the formation to bombardment by neutrons or gamma rays. These include:
   - Gamma-ray logs record the naturally occurring gamma rays in the rock formation surrounding the well bore. They differentiate between shales and other formations, or measure the amount of shale in the formation.
   - Neutron logs bombard the formation with neutrons and measure the induced gamma rays: They delineate porous formations, and indicate the amount of fluid (and, in some cases, fluid type). They are useful in locating gas zones and determining rock types.
   - Formation density logs measure the scattering of gamma rays bombarding the formation from a source on the logging tool. They are used to determine porosity, and help in determining rock types in conjunction with sonic or neutron logs.
   - Gamma spectrometry logs measure both the scattered neutrons and the gamma-ray spectrum from neutron bombardment. They help in measuring 'hydrocarbon saturation, porosity, formation water salinity, and rock types.
3. Acoustic velocity, or sonic logs, measure the velocity of an acoustic (sound) wave along the wall of the borehole. They are used to measure porosity, to distinguish between salts and anhydrites, to detect shales with abnormal pressures, to determine rock types, and to identify fractures.
4. Nuclear magnetism logs measure the effects of applying a large magnetic field to the rock formation. They are used to measure permeability, porosity, producibility, and water saturation.
5. Temperature logs are used to identify zones where drilling mud is being lost into the formation or, in air-drilled wells, the locations of gas entry into the wellbore.

SOURCES: F. A. Giuliano (cd.), *Introduction to Oil and Gas* Technology, 2d ad., Intercomp Resource Development and Engineering, Inc., Houston, TX, 1981; British Petroleum Co. Ltd., Our *Industry Petroleum*, 1977; and Schlumberger Well Services, *Openhole Services Catalog*, 1983.

# Appendix C
# Double Counting

## A Comparison of the PGC and NPC Tight Gas Estimates

A major problem with estimating the natural gas resource from unconventional reservoirs is determining how much of this unconventional gas has already been included in estimates of the conventional resource. The primary areas of overlap would be the tight sands and Devonian shales. Much of the tight sands represents the lower end of a continuum of gas-producing reservoirs. Except for its lower porosities and permeabilities, the "blanket" portion of the tight sands resource is quite similar in other respects to conventional formations and, in fact, gas is presently being produced from tight blanket formations and even, in some cases, from lenticular formations. The Devonian shales have been producing gas since the early days of petroleum development in this country. Obviously, these categories cannot be considered entirely new additions to the resource base.

There is no clear-cut boundary between gas that has been included in conventional resource estimates and that which has not. The cutoff point for the conventional resource varies from assessment to assessment and tends to be loosely defined on the basis of rather ill-defined economic and technical constraints. For example, the Potential Gas Committee (PGC) defines its resource estimate to include gas from "all wells which would be drilled in the future under assumed conditions of adequate economic incentives in terms of price/cost relationships and current or foreseeable technology."[1]

The PGC assessment, *Potential Supply of Natural Gas in the United States,* is one estimate of the conventional resource which overlaps with the "unconventional." Given its broad definition of what constitutes the undiscovered recoverable resource, the PGC chose not to define a physical cutoff point, such as a permeability limit, to separate out tight gas from conventional gas. To do so would exclude from the resource base gas that conceivably could be produced under the assumptions of reasonable price and technology. Thus, the PGC has consistently designated some "tight" gas as part of the conventional resource.

Recently, the PGC has made an attempt to determine the percent of its total resource estimate that occurs in tight formations. (It includes in the tight gas category both tight sands and Devonian shales.) For each of its reporting areas (fig. C-1 (a)), it estimates the percentage of gas that occurs in tight formations, above and below 15,000 ft. Table C-1 gives the PGC estimates, in TCF, for each reporting area.[2] The total tight gas included in these estimates is 172 TCF, or 20 percent of the total potential resource.

The following analysis compares the PGC tight gas breakout with the National Petroleum Council's (NPC) estimates of tight sands and Devonian shale resources.[3] It has been suggested that there may be a considerable amount of overlap between these two estimates. Because estimates of the United States' gas resource base and future supply often add conventional and unconventional gas contributions, elimination of any overlap would decrease the projected total resource base and supply. Additionally, since an overlap is most likely to occur among the most attractive gas prospects, elimination of the overlap may affect near- and mid-term supply forecasts disproportionately.

In order to compare the PGC breakout with the NPC estimates, the assumptions underlying the estimates need to be reviewed. Some of the assumptions are documented, others have been confirmed through personal communications.

The definition for tight gas used by the PGC is similar to the FERC definition and includes all gas in formations with average permeabilities less than 0.1 millidarcy (md). The NPC report does include some gas in formations with average permeabilities greater than 0.1 md, but the amount is small, less than 1 trillion cubic feet (TCF). Therefore, the permeability levels for the two estimates are generally compatible.

Not all the gas in the PGC tight gas estimate will overlap the NPC estimate. For example, PGC tight gas includes gas from new pools and reservoirs in formations that are already being produced. By definition, this gas is mostly accounted for in the probable category.[4] The NPC report specifically **excludes areas already producing tight gas from its evaluation, since its objective is to estimate "new potential** reserve additions." Thus, tight gas in the PGC probable category, amounting to some 56 TCF, cannot be part of any overlap between the two estimates.

The NPC report does not include any potential gas resources in formations at depths greater than 15,000 ft, although it postulates that a significant additional

[1] Potential Gas Agency, *Potential Supply of Natural Gas in the United States (as of Dec. 31, 1980), 1981.*

[2] Based on the 1982 revised figures for the total resource: Potential Gas Agency news release, February 1983.

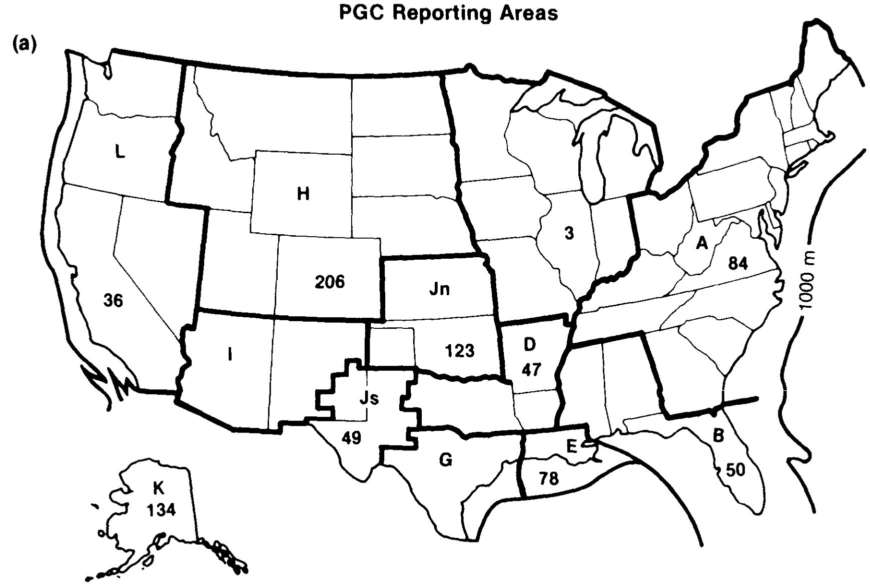
[3] National Petroleum Council, *Unconventional Gas Sources, 1980.*

[4] Harry Kent, Director, Potential Gas Agency, personal communication, 1984.

**Figure C-1.—PGC and NPC Reporting Areas**

**PGC Reporting Areas**

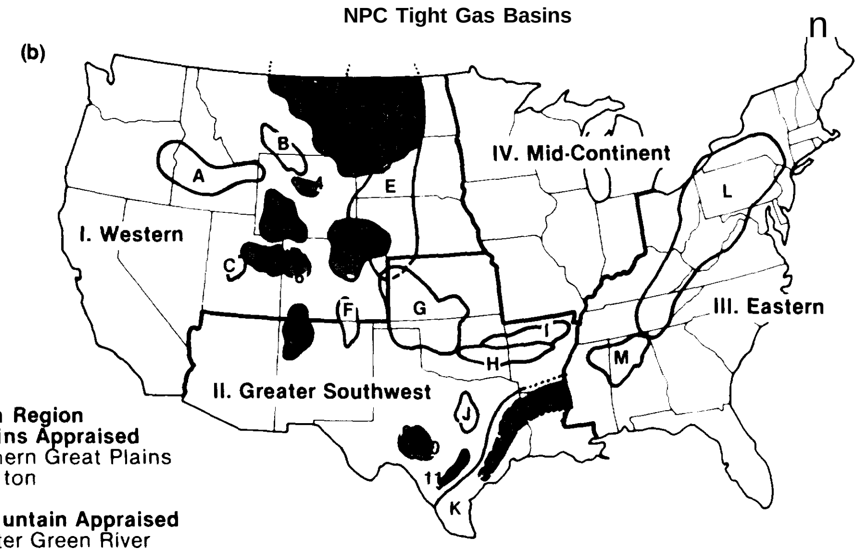
(a)




NOTE: From Figure 1—Reporting areas and total potential gas supply. 1982 Potential Gas Committee

**NPC Tight Gas Basins**

(b)




**1. Western Region**
**Great Plains Appraised**
1. Northern Great Plains
2. Williston

**Rock Mountain Appraised**
3. Greater Green River
4. Wind River
5. Uinta
6. Piceance
7. Denver

**Other Known Western**
A. Snake River
B. Big Horn
C. Wasatach
D. Douglas Creek
E. Western Shallow Cretaceus Trend

Basins studied by NPC

**II. Greater Southwest Region**
**Southwest Appraised**
8. San Juan
9. Val Verde-Ozona Trend
10. Val Verde-Sonora Trend
11. Edwards Lime Trend
12. Cotton Valley Trend

**Other Known Southwest**
F. Raton
G. Anadarko
H. Ouachita
1. Arkoma
J. Fort Worth
K. Western Gulf Coast

**III. Eastern Region**
L. Appalachian
M. Black Warrior

**Table C.1.— PGC Estimate of Gas Occurring in Tight Formations Included in Its 1982 Estimate of Total U.S. Undiscovered Recoverable Resources** (in TCF)

| | Probable | | Possible | | Speculative | | |
|---|---|---|---|---|---|---|---|
| PGC area | <15,000 | >15,000 | <15,000 | >15,000 | <15,000 | >15,000 | Total |
| A | 23.49 | — | 0.4 | — | — | — | 23.89 |
| B | 0.32 | 0.18 | 0.24 | 0.3 | 0.3 | 0.48 | 1.82 |
| c | — | — | — | — | — | — | — |
| D | 0.8 | — | 3.0 | — | 3.0 | 0.8 | 7.6 |
| E | — | | — | | — | | — |
| G | 0.28 | 03 | 0.54 | 048 | 0.12 | 016 | 1.88 |
| H | 21.75 | 5 | 14.43 | 14.56 | 7.02 | 29.2 | 91.96 |
| I | 0.94 | — | 0.33 | – | — | — | 1.27 |
| Jn” | — | 1.98 | | 14.06 | 3 | 20.06 | 40.2 |
| Js | 0.49 | — | 0.38 | – | — | — | 0.87 |
| L | 0.04 | 0.3 | 0.3 | 0.6 | 0.7 | 0.4 | 2.34 |
| Total | 55.87 | | 50.72 | | 65.24 | | 171.83 |

SOURCE” Potential Gas Agency. Potential *Supply of Natural Gas in the United States (as of Dec 31, 1982),* Report of the Potential Gas Committee, Colorado School of Mines, June 1983

resource could exist at these depths. However, over half of the PGC tight sands estimate is found at greater than 15,000 ft depths—89 TCF total, 81 TCF in the possible and speculative categories. We assume that there is no overlap between the PGC tight gas below 15,000 ft and the NPC estimate.

The gas projected by the NPC to be recoverable from tight sands at $5.00/MCF,[5] with a 15 percent discounted cash flow rate of return (DCF ROR) and using base technology, is assumed to represent a reasonable upper economic limit to gas that might be included in the PGC estimate[6] (the N PC's “maximum recoverable” gas would be an extreme upper limit). In other words, tight gas considered produceable at less than $5.00/MCF using present technology is likely to be included in the PGC tight gas estimate.

In summary, the most potential for overlap exists between the PGC tight gas in the possible and speculative categories at less than 15,000 ft and the NPC tight sands and Devonian shales gas recoverable at $5.00/MCF (1979$) using base technology. This is graphically represented in figure C-2. It should be noted that the overlap determined by a straightforward comparison using the above assumptions may be too large. PGC used FERC criteria as a guide to defining the tight formations and the FERC interpretation of what constitutes tight gas has tended to be generous relative to the NPC interpretation.

Other specific assumptions need to be made to compare individual areas. These are discussed in more detail below.

## Areas of Overlap

The PGC reporting areas and the NPC appraised and extrapolated basins are shown in figure C-1 (a) and (b), respectively. Table C-2 lists the comparable areas and notes where the PGC has specifically identified tight gas included in the potential resource. The total PGC estimate of gas in tight formations is about 172 out of a total of 870 TCF, or approximately **20 percent of the remaining undiscovered recoverable resource. NPC estimates 607** TCF of recoverable gas from tight sands[8] and an additional 25 TCF, at least, from Devonian shales. Our comparison attempts to determine how much of this 633 TCF of gas has already been included in the PGC estimate of conventional undiscovered resources and cannot be considered as additions to the U.S. resource base.

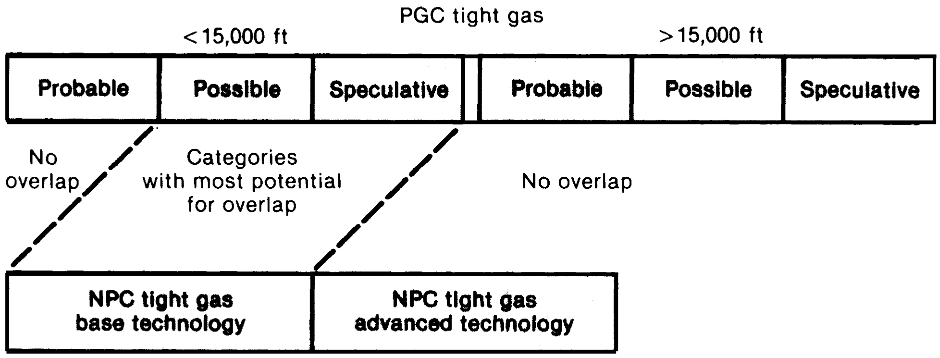
Our analysis indicates that the greatest potential for overlap occurs in the Rocky Mountain region covered by the PGC reporting area H (fig. C-1 (a)). The comparable NPC area is the Rocky Mountain Basins plus the Northern Great Plains (fig. C-1 (b)). This area is already the site of considerable production of gas from tight formations (e.g., from the Wattenberg field of the Denver Basin). The extent of the duplication is summarized in table C-3.

For a first approximation, we assume that the PGC tight gas does not include gas from the Northern Great Plains.[9] Basins that probably are included in both Rocky Mountain estimates are the Greater Green River, Uinta, Piceance, Wind River, and Denver basins, Within these basins, the most likely overlap occurs between the blanket formations of the NPC re-

[5]For simplicity, the N PC prices (in 1979 dollars) are used in this analysis.
[6]The “boundary conditions' for the PGC resource estimate are imprecise, and no limit on price is specified other than what may be inferred from the phrase “adequate economic Incentives in terms of price/cost relationships, ”
[7]To be precise, the NPC definition of its “base case” technology allows evolutionary improvements in presently available technology.

@This is the “maximum recoverable” gas. Using present technology, NPC estimates that 365 TCF would be recoverable at $5.00/MMBtu
[9]Kent, op. cit.

**Figure C-2.— PGC and NPC Categories of Tight Gas**




NPC tight gas
(includes both tight sands and Devonian shales)

SOURCE Off Ice of Technology Assessment,

**Table C.2.—Comparable Areas—PGC Report and NPC Report**

| PGC reporting areas | Comments | NPC basins |
|---|---|---|
| Area A. . . . . . . . . . . . . . . . . . . . . | Includes some Devonian shales recoverable by normal drilling, well stimulation, and completion and analogous in geologic setting to previous production | Appalachian Basin Devonian shales<br>Eastern extrapolated tight sands |
| Area B. . . . . . . . . . . . . . . . . . . . . | — | Eastern extrapolated tight sands |
| Area D. . . . . . . . . . . . . . . . . . . . . | Includes tight formations of Travis Peak and Cotton Valley | Cotton Valley appraised, Southwest extrapolated (east) |
| Area G . . . . . . . . . . . . . . . . . . . . | — | Edwards Lime Trend, Southwest extrapolated (south) |
| Area H . . . . . . . . . . . . . . . . . . . . | Includes tight formations of Greater Green River, Uinta, Piceance, and Wind River | Rocky Mountains appraised, Northern Great Plains appraised, Western extrapolated |
| Area I . . . . . . . . . . . . . . . . . . . . . | — | San Juan appraised, Southwest extrapolated (west) |
| Area J north. . . . . . . . . . . . . . . . | — | Southwest extrapolated (east) |
| Area J south . . . . . . . . . . . . . . . | — | Val Verde Ozona-Sonora appraised, Southwest extrapolated (central) |

SOURCE: Office of Technology Assessment

**Table C-3.–Comparison of PGC and NPC Tight Gas Resource, Rocky Mountain Region (in TCF)**

| NPC Rocky Mountain Basins[a] | Recoverable $5.00/McFb | Maximum recoverable | PGC area H <15,000 ft | Tight gas | Percent overlap |
|---|---|---|---|---|---|
| Blanket . . . . . . . . . . . . . . . . . . . . | 19.7 | 34.5 | Probable | 21.75 | None |
| | | | Possible | 14.43 | 62-100 |
| | | | Speculative | 7.02 ) | |
| Lenticular. . . . . . . . . . . . . . . . . . | 68.9 | 164.9 | | | None |
| Combined. . . . . . . . . . . . . . . . . . | 12.6 | 15.5 | | | None |
| Total , . . . . . . . . . . . . . . . . . . . . . | 101.2 | 214.9 | Total | 43.20 | 10-21 |

[a]Includes. appraised Greater Green River, Uinta, Piceane, and Denver basins, and other Western *extrapolated basins.*
[b]*Gas recoverable* at $500/MCF (1979$), 1570 DCF ROR, assuming base technology.

SOURCE Office of Technology Assessment

port and the PGC possible and speculative categories at depths less than 15,000 ft. We are assuming that the PGC estimate does not include any gas in lenticular formations or in combined blanket and lenticular formations. This assumption may not be strictly correct because individual lenses have been produced in past drilling by directly intersecting the lens with the wellbore. There is no existing technology, however, for producing lenses remote from the well bore.

Much of the Rocky Mountain gas occurring in blanket formations appears to be included in both the NPC and PGC estimates. The NPC estimated range of gas recoverable in blanket formations, from gas available at $5.00/MCF, 15 percent DCF ROR, and base technology, to the maximum recoverable gas, is **20 to 34** TCF (see vol. V, table 9 of the NPC report). This includes 7 to 10 TCF in extrapolated blanket formations in this region. The NPC estimate for gas in blanket formations is very close to the PGC estimate of 21 TCF of possible and speculative gas occurring in tight formations at less than 15,000 ft, and probably represents a duplication of the PGC estimate.

Another significant area of overlap may occur in the Cotten Valley Trend of east Texas and Louisiana. This area is included in PGC area D and is one of the appraised basins of the NPC report. The NPC range of gas in the Cotton Valley, from $5.00 to the maximum recoverable, is 7 to 12 TCF, which probably overlaps the 6 TCF of possible and speculative tight gas in formations less than 15,000 ft as estimated by the PGC.

In south Texas, the NPC estimate ranges from **44 (at $5.00) to 60 TCF (maximum recoverable).** The estimate covers extrapolated formations as well as the appraised Edwards Lime Trend, with an estimated gas potential between 6 TCF (at $5.00) and 9 TCF (maximum recoverable). it is also covered by PGC reporting area G. Here, PGC estimates 0.66 TCF of gas in the possible and speculative categories above 15,000 ft. It is likely that the PGC estimate, even if it does not specifically refer to the Edwards Lime Trend, is duplicated somewhere in the NPC appraised plus extrapolated formations.

In the PGC's area 1, including the San Juan Basin, most of their estimated tight sands gas is derived from infill drilling of the Dakota and Mesaverde formations and is most likely included in its probable category. The 0.33 TCF remaining in the possible category may be new gas occurring in these formations, and most or all of it may overlap the NPC estimates of 1.49 to 2.31 TCF for the appraised San Juan Basin. Although the NPC extrapolates an additional 11 to 16 TCF in this region (which would include gas in the Raton Basin in northeastern New Mexico), the PGC estimate probablv does not overlap with any extrapolated gas.

A large quantity of gas–40 TCF–is estimated by the PGC to occur in tight formations within its reporting area Jn. Most of this gas is thought to be found in the Deep Anadarko and Springer sands. Thirty-six TCF are found at depths greater than 15,000 ft. This leaves only 4.1 TCF in the possible and speculative categories above 15,000 ft to potentially overlap the NPC tight gas. All the NPC basin estimates in this region are extrapolations with a total range from 16 to 24 TCF. It is likely, but not conclusive, that the 4.1 TCF of PGC gas does overlap NPC gas.

The amount of overlap in tight formations in the Eastern United States is more difficult to determine. This area encompasses reporting areas A and B of the PGC report and the Eastern U.S. extrapolated tight sands and the Appalachian Basin Devonian shale of the NPC report. in area A, excluding the estimated probable gas, which is likely to be primarily gas from producing formations in Devonian shales and interlayered sandstones, leaves 0.4 TCF in the possible category. In area B, there are 0.54 TCF in the possible and speculative categories at depths less than 15,000 ft.

Producible gas from Devonian shales as estimated by the NPC falls in the range of 12 TCF at $5.00/MCF and 25 TCF maximum recoverable using traditional technologies only. The extrapolated tight sands resource for the Eastern United States ranges from 72 to 101 TCF. In OTA's opinion, the 0.94 TCF of gas in the PGC areas A and B are likely to be included somewhere in the total of the NPC extrapolated tight sands and the Devonian shale resource,

Table C-4 summarizes the total overlap between NPC and PGC estimates, amounting to approximately 30.5 TCF. The percent reduction due to duplication for the total NPC tight gas resource (including both tight sands and Devonian shales) is 8 percent for the gas recoverable at $5.00 and 5 percent for the maximum recoverable gas.

The amount of overlap, then, is not vitally important in terms of reducing the size of the total additional resource from unconventional reservoirs. More important are the specific areas of overlap, since these oc-

**Table C-4.–Overlap of PGC and NPC Resource Estimates**

| PGC total tight gas | NPC total recoverable gas tight sands and Devonian shales | | Total overlap |
|---|---|---|---|
| | At $5.00[a] | Maximum | |
| 171.83 TCF | 376.6 TCF | 633.5 TCF | 30.5 TCF |

aGas recoverable at $5.00/MCF (1979$), 15%. DCF ROR, assuming base technology,

SOURCE: Office of Technology Assessment

cur in areas which have been predicted to be main contributors to supply in the next **20 years.**

**For example, the** NPC estimates that the Rocky Mountain Basins will contribute over 14 TCF to production over the next 20 years and 43 TCF to reserve additions, according to its standard development scenario. It is likely that much of this production will be from the blanket formations, as these are generally the more profitable prospects. However, if these formations are already partially counted in conventional resource estimates, and these estimates are used in forecasting supply, what the NPC is estimating cannot be considered as additions to existing projections of future conventional supply.

Another primary contributor to the NPC reserve addition and supply forecasts in the next 20 years is the Greater Southwest, including primarily the Cotton Valley, the Val Verde Ozona-Sonora Trend and the Edwards Lime Trend. The Cotton Valley Trend potential, however, appears to be duplicated in the PGC report; thus it, also, cannot contribute additional reserves or supply.

This analysis deals only with the overlap between the PGC and the NPC assessments of the natural gas resource. Similar duplication is Ii kely to exist in other geologically based estimates such as the U.S. Geologic Survey's (USGS) estimate of undiscovered recoverable gas resources.[10] However, because of varying approaches to estimating the resource, no categorical statement of the amount of overlap between conventional and unconventional resource estimates can be made.

A final comment needs to be made regarding the PGC estimates of tight gas recoverable from formations at depths greater than 15,000 ft. This gas represents a resource additional to the N PC estimated tight sands resource, In general, these resources would be considered even less economic to produce than the NPC gas because of the higher costs and greater technical difficulty of drilling and fracturing at these depths. However, Potential Gas Committee members felt that the technology did exist to produce tight gas from deep formations, and under certain conditions there might be sufficient incentive to produce this gas. Nevertheless, we feel that the 89 TCF of deep tight gas in the PGC estimate should be regarded with at least as much, if not more, caution than the NPC estimates in terms of evaluating their potential for contributing to near- and mid-term supply.

[10] G L. Dolton et al., *Estimates of Undiscovered Recoverable Conventional Resources of Oil and Gas in the United States,* U.S. Geological Survey Circular 860, 1981.

# Appendix D
# Glossary

**adsorbed gas:** Natural gas that is physically bound to the surfaces of the reservoir rock.

anaerobic: Conditions that exist only in the absence of oxygen.

anisotropy: A characteristic of certain rocks wherein certain properties, such as permeability, exhibit different values when measured along axes in different directions.

**anticline:** A fold, generally convex upward, whose core contains stratigraphically older rocks.

**associated dissolved gas:** Natural gas that occurs together with oil in a reservoir, either dissolved in the oil (dissolved gas) or as a gas cap above the oil (associated gas).

**blanket formations:** Thin gas-bearing formations that take the form of one or several stacked layers extending laterally over a wide area.

**borehole shooting:** A method of stimulating increased gas flow by detonating explosives inside the borehole of a well.

**cleat:** The pervasive, vertically oriented natural fracture system in coal seams.

**coal seam (coalbed) methane:** Natural gas formed as a byproduct of the coal formation process and trapped in the coal seam.

**combination trap:** A trap for oil or gas that has both structural and stratigraphic elements.

**deviated drilling:** Drilling that has been deliberately angled away from the vertical.

**Devonian shale gas:** Gas trapped in the shales of Devonian age located in the Eastern United States, primarily in the Appalachian, Michigan, and Illinois basins.

**extension test: A well drilled to extend the areal limits of a partially developed pool. May sometimes become a new pool discovery well. Also known as outpost well.**

**fault: A sudden displacement** of rock strata along a fracture.

**field:** Composed of a single pool or multiple pools that are grouped on or related to a single structural and/or stratigraphic feature.

**formation:** A rock mass composed of individual beds or units with similar physical characteristics or origin.

**formation damage:** A reduction in permeability caused by drilling, fracturing, or producing a well–e.g., by the plugging of pores by water-sensitive clays dislodged or caused to swell by water-based fracture fluids or drilling fluids.

**formation water:** Water present in a water-bearing formation under natural conditions, as opposed to introduced fluids, such as drilling mud.

**infill drilling:** Drilling at a smaller spacing than called for in the original development plan, designed to speed up production and/or increase ultimate recovery.

**interference:** A condition whereby adjacent wells in a field are close enough together that their areas of (pressure) influence overlap, generally reducing "per well" gas recovery below the level that would be obtained with an isolated well.

**lens:** An individual reservoir in a tight lenticular formation (see below), often oval in cross-section.

**lenticular formation:** A thick formation containing large numbers of small, separate, lens-like reservoirs interspersed with impermeable shales or coal.

**lineament:** A linear feature of the Earth's surface that may reveal a subsurface feature such as a fault.

log, **well log:** Measurements of the physical properties of a reservoir, taken while drilling, generally by lowering measurement devices down the well bore.

**massive hydraulic fracturing (MHD): Creation** of large, manmade fractures in reservoir rock by pumping fluids into a well under high pressures. "Frac" jobs generally are considered "massive" when the volume of fluid used is 100,000 gallons or more, but there is no universally accepted criterion.

**methane:** The primary constituent of natural gas, the gaseous hydrocarbon $CH_4$.

**natural fracture system:** A series of fractures, often aligned in some way, created by natural processes.

**new field wildcat:** A well drilled in search of oil or gas in a geological structural feature or environment that has never before been proven productive.

**new pool wildcat: Well** drilled in search of pools above (shallower pool test), below (deeper pool test), or outside the areal limits of already known pools in fields that have already been proven productive. May sometimes become an extension well.

**nonassociated gas:** Natural gas that occurs in a reservoir without oil.

**outpost well: See extension test.**

**pay:** A rock stratum or zone that yields oil or gas.

**permeable:** Having the property or capacity of a porous rock, sediment, or soil for transmitting a fluid; it is a measure of the relative ease of fluid flow under unequal pressure.

**petroleum:** A general term for all naturally occurring hydrocarbons, whether gaseous, liquid, or solid.

**play:** A rock formation or group of formations within a sedimentary basin with geologic characteristics similar to those that have been proven productive. A play serves as a planning unit around which an exploration program can be constructed. May also refer to the exploratory effort, often following a significant discovery, that uses a geologic idea to determine where petroleum can be found.

**pool:** A subsurface accumulation of oil and/or gas in porous and permeable rock, having its own isolated pressure system. Theoretically, a single well could drain a pool. Also known as a reservoir.

**porosity: The percentage of the bulk** volume of a rock or soil that is occupied by interstices (gaps between the particles that compose the rock), whether isolated or connected.

**proppant:** Small particles of a hard material (sand, bauxite, etc.) that are suspended in fracturing fluid, to be left behind when the fluid is removed to prevent the created fractures from closing under the pressure exerted by the overlying rock.

**prospect: An area that is a potential site of economically recoverable petroleum accumulation based on preliminary exploration.**

**province: A region in which a number of oil and gas pools and fields occur in a similar or related geological environment.**

**reserves:** The portion of the total gas resource base that has been identified by drilling and estimated directly by engineering measurements, and that is recoverable at current prices and technology.

**reservoir: See *pool.***

**reservoir rock:** Any porous and permeable rock that yields oil or gas. Sandstone, limestone, and dolomite are the most common reservoir rocks, but gas accumulation in the fractures of less permeable rocks also occurs.

**resources:** The total amount of oil or gas that remains to be produced in the future. Generally does not include oil or gas in such small deposits or under such difficult conditions that it is not expected to be produced at any foreseeable price/technology combination.

**secondary migration:** The movement of fluids within the permeable reservoir rocks that eventually leads to the segregation of oil and gas into accumulations in certain parts of these rocks.

**sedimentary basin:** A low area in the Earth's crust, caused by Earth movements, in which sediments have accumulated.

**sedimentation:** The act or process of forming or accumulating sediment in layers, including such processes as the separation of rock particles from the material from which the sediment is derived, the transportation of these particles to the site of deposition, the actual deposition or settling of the particles, the chemical or other changes occurring in the sediment, and the ultimate consolidation of the sediment into solid rock.

**source rock: Sedimentary rock in which organic material under pressure, heat, and time was transformed to liquid or gaseous hydrocarbons.** Source rock is usually shale or limestone.

**stimulation:** Any process that mechanically or chemically disturbs the reservoir rock in order to increase gas flow to the well.

**stratigraphic trap:** A trap for oil or gas, resulting from changes in rock type, porosity, or permeability, that occurs as a result of the sedimentation process rather than structural deformation.

**structural trap: A trap for oil or gas resulting from fold**ing, faulting, or other deformation of the Earth.

**thermal maturity:** The extent to which the organic matter in sedimentary rocks has been "cracked"-broken into simpler molecules–by heat.

**trap:** Any barrier to the upward movement of oil or gas that allows either or both to accumulate. A trap includes a reservoir rock and an overlying impermeable roof rock; the contact between these is concave, as viewed from below. See also stratigraphic, structural, and combination traps.

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