Chapter 7

Introduction and Summary: Availability of Unconventional Gas Supplies

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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.

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.

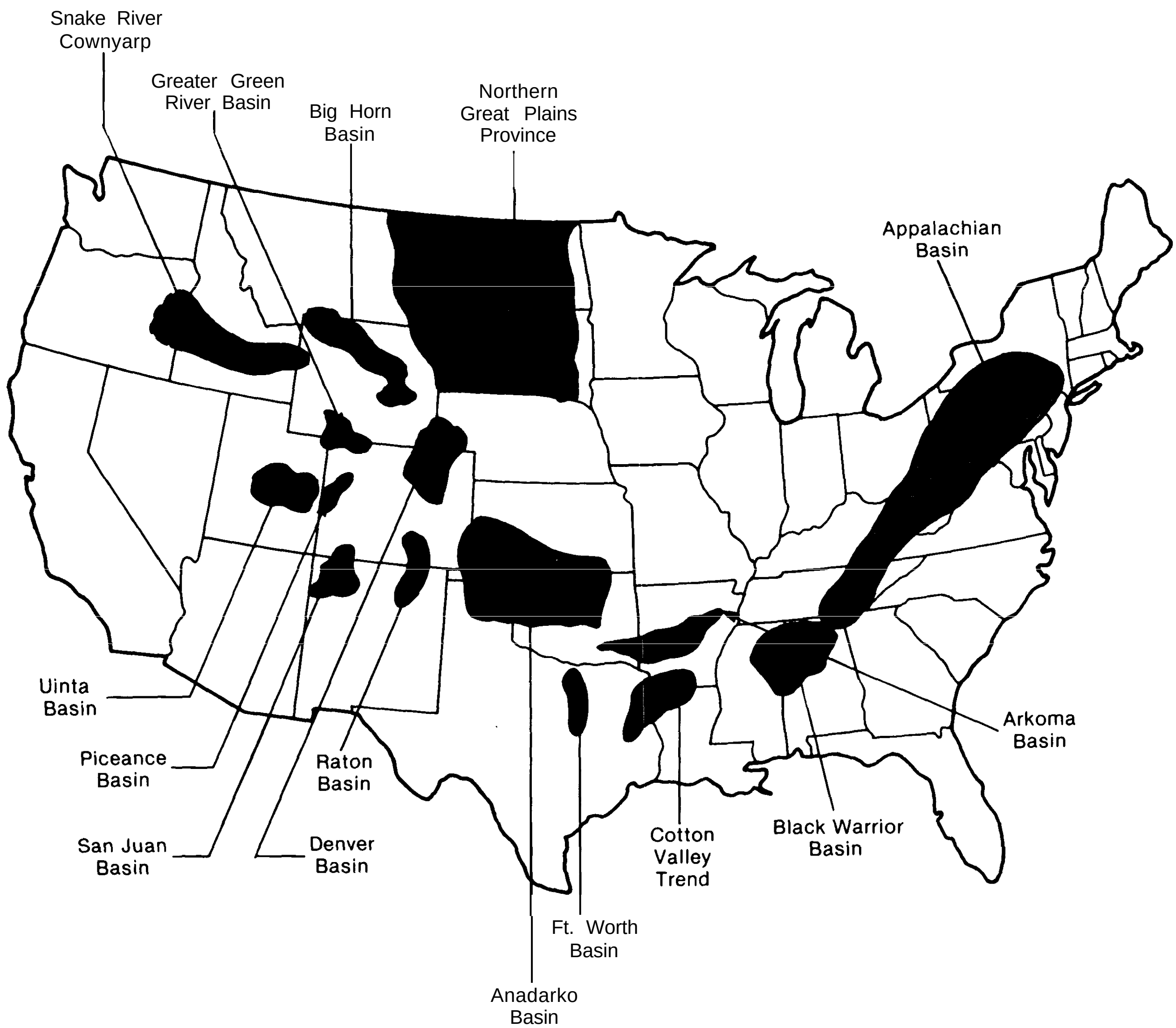
[6]This category is meant to include only those resources that can be extracted by technologies ordinarily used tor gas production For example, gas that theoretically could be obtained by mining and retorting shales would be excluded.

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 in 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 i n 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. " 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.

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

[13] However, gas formed in coal seams and trapped in adjacent formations has been produced in quantity.

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.